31/2

PRODUCTION TESTS

Objectives

The objectives of the full scale production te

1. To obtain positive evidence of the type o ... various depths.

2. To assess well inflow performance, including permeability, skin and turbulence in the oil zone, the relatively tight micaceous sand gas zone and the highly permeable clean sand gas zone.

3. To investigate sand influx problems and efficiency of the gravel pack used for the clean sand gas test.

4. To obtain PVT samples to be used for compositional and phase behaviour analyses.

5. To obtain accurate on site measurements of liquid yields and trace elements in the two gas tests.

Summary and General Results

A total of four intervals were tested. A drill stem test was performed in the water zone at 1600.5 - 1605 m BDF. Tests with regular production strings and perforated completions were carried out in the oil zone at 1577.5 - 1582.5 m BDF and in the micaceous part of the gas bearing section at 1520 - 1535 m BDF. The top clean part of the gas section was tested with a production string and an internal gravel pack completion at 1435 - 1460 m BDF (See Fig. I/9.3).

After the bottom hole test valve was opened for the DST in the water zone, the well flowed for 17 minutes until it died. Some 87.5 liters of formation water (70,000 ppm NaCl equivalent) were recovered.

In the test on the oil zone the well came in at a low rate and flowed at about 30 - 40 B/D for four days. The oil was about 24^{o} API and the GOR around 200 SCF/B. A buildup towards the end of the test indicated a formation permeability of some 20 md and no skin (See Figs. I/9.8, I/9.9 and Table I/9.5).

The micaceous gas zone test stabilized at a rate of about 5 MMSCF/D on 28/64" choke during the clean up period. The tubing head pressure was about 1200 psig. A sequential rate test followed with an extended maximum rate of about 6 MMSCF/D. However, analysis of the bottom hole pressures indicated that the well inflow performance was improving gradually during the sequential test. Thus the rate-dependent skin or turbulence could not be determined. The build-up following the last rate of this sequential test indicated a kh value of about 765 mdft corresponding to a permeability of 16 md. The skin factor (including turbulence) was estimated at 25 (76% of drawdown) (Refer to Figs I/9.12, I/9.13 and Table I/9.10).

PRODUCTION TESTS

31/2-3

Objectives

The objectives of the full scale production tests were as follows:

1. To obtain positive evidence of the type of reservoir fluid at various depths.

2. To assess well inflow performance, including permeability, skin and turbulence in the oil zone, the relatively tight micaceous sand gas zone and the highly permeable clean sand gas zone.

3. To investigate sand influx problems and efficiency of the gravel pack used for the clean sand gas test.

4. To obtain PVT samples to be used for compositional and phase behaviour analyses.

5. To obtain accurate on site measurements of liquid yields and trace elements in the two gas tests.

Summary and General Results

A total of four intervals were tested. A drill stem test was performed in the water zone at 1600.5 - 1605 m BDF. Tests with regular production strings and perforated completions were carried out in the oil zone at 1577.5 - 1582.5 m BDF and in the micaceous part of the gas bearing section at 1520 - 1535 m BDF. The top clean part of the gas section was tested with a production string and an internal gravel pack completion at 1435 - 1460 m BDF (See Fig. I/9.3).

After the bottom hole test valve was opened for the DST in the water zone, the well flowed for 17 minutes until it died. Some 87.5 liters of formation water (70,000 ppm NaCl equivalent) were recovered.

In the test on the oil zone the well came in at a low rate and flowed at about 30 - 40 B/D for four days. The oil was about 24^{o} API and the GOR around 200 SCF/B. A buildup towards the end of the test indicated a formation permeability of some 20 md and no skin (See Figs. I/9.8, I/9.9 and Table I/9.5).

The micaceous gas zone test stabilized at a rate of about 5 MMSCF/D on 28/64" choke during the clean up period. The tubing head pressure was about 1200 psig. A sequential rate test followed with an extended maximum rate of about 6 MMSCF/D. However, analysis of the bottom hole pressures indicated that the well inflow performance was improving gradually during the sequential test. Thus the rate-dependent skin or turbulence could not be determined. The build-up following the last rate of this sequential test indicated a kh value of about 765 mdft corresponding to a permeability of 16 md. The skin factor (including turbulence) was estimated at 25 (76% of drawdown) (Refer to Figs I/9.12, I/9.13 and Table I/9.10).

When the well was beaned up after the shut-in it became obvious that the inflow performance continued to improve and finally a rate of 30 MMScf/D was achieved with a tubing head pressure of about 700 psig. A buildup following this rate indicates a kh of about 12000 mdft which is 16 times the value from the first buildup. (See Fig. I/9.14 and Table I/9.12) The skin factor (including turbulence) was estimated at 116 or 95% of drawdown. The explanation for the increased kh could be that a channel developed behind the casing creating communication with the better sand some 10 meters above the top of the perforations.

Evaluation of the variable rate test following the buildup indicates that some 78% of the drawdown prior to the buildup was caused by turbulence. The Darcy skin factor was estimated at 23.5 (See I/9.15 and Table I/9.13).

The results from the third and last pressure buildup were essentially equivalent to those obtained in the second buildup.

The clean sand gas test which was performed with a gravel pack completion, was dominated by severe turbulence effects. After the initial clean up at 13 - 17 MMSCF/D flow rate, the well produced at maximum rate of about 40 MMScf/D. Restrictions through surface facilities maintained the tubing head pressure at 800 psig. In the first buildup the pressure stabilized in 3 minutes, indicating a very high transmissibility together with high turbulence and skin effects. It is not possible to derive a value for kh from the buildup. The second and third buildups were similar.

The variable flow period following the second buildup provided valuable quantitative information. The drawdown is essentially caused by turbulence as illustrated in Fig. 35. Assuming no Darcy skin (which is unlikely) the smallest possible permeability value was estimated at 1.7 D. It is, however, reasonable to assume same Darcy skin factor and thus a permeability which is much higher than the indicated minimum value. The fourth and last buildup (See Fig. I/9.23 and Table I/9.19) indicated that the permeability might be in order of 8D.

The test interpretations can be summarized as follows:

Zone	Rate MMSCF/D (B/D)	kh mdft	Perm. md	Total Skin Incl. Turb. Factor	Total Skin Incl. Turb. % of Drawd.	Darcy Skin Factor	Darcy Skin % of Drawd.
Oil Zone	(32)	334	20	0	0	0	0
Mic. Gas Zone							
First BU	6.0	765	16	25	76	N.A.	N.A.
Second BU	32.6	12177	N.A.	116	95	23.5	17
Clean Gas Zone							
Min Case	38.1	144500	1700	632	99	0	0
Possible Case	38.1	635000	7700	2800	> 99	24	< 1

31/2-3 DRILL STEM TEST

A drill stem test was performed on the interval 1600.5 - 1605 m. From logs, the interval was thought to be water productive, but have approximately 15% oil saturation. The object of the test was to obtain a formation water sample and to determine whether any oil was producible.

The assembly was run as shown, (Fig. I/9.3) with 1250 m of fresh water cushion providing 500 psi drawdown on the formation. The RTTS packer was set at 1574 m, and after opening the APR-N valve indications of inflow was observed for 17 minutes. The level of the water cushion rose 275 m to 49 m BDF before the well was dead.

87.5 litres of formation water were recovered from the sample chamber, in four samples. The resistivities of the samples were measured, and are given below together with calculated salinities.

Sample no	Volume(litres)	Resistivity(Ohm, m) at 11^{o} C (52°F)	Salinity (ppm NaCl) calculated
1 (bottom of chamber)	25	0.155	67,000
2	25	0.152	68,000
3	25	0.153	68,000
4 (top of chamber)	12.5	0.145	69.000

N.B. Brine resistivity 0.0606 ohm m at 14.5^{o} C +/- 200,000 ppm
Water resistivity 3.340 ohm m at 14.5^{o} C +/- 2100 ppm

Thus samples are considered representative of formation water as a salinity of some 70,000 ppm was predicted from logs.

From the pressure gauges, a formation pressure of 2307 psig was calculated. This corresponds well with the RFT data. (See Fig. I/9.1).

OIL ZONE PRODUCTION TEST

Objectives

The oil zone production test was carried out on the interval 1577.5 - 1582.5 m, which logs had indicated to be oil bearing. The objectives were as follows:

a) to test the presence of movable oil
b) to ascertain at what rate this oil might be produced
c) to evaluate well inflow performance and possible water and/or gas coning effects
d) to obtain PVT samples

Test Description

The production test string having been run (see Fig. I/9.4), the surface equipment was installed (as Fig. I/9.5), except that for the oil test the sand trap, sand detection equipment and the Thornton sampling equipment were not required. The tubing was displaced to diesel through the XA-SSD, and the zone was perforated. The test sequence is shown in Fig. I/9.6.

After the well was perforated, it was cleaned up at a rate less that 100 B/D on a 4/64" choke. One Sperry Sun, and one Amerada pressure gauge were run, and the well was then flowed on an 8/64" choke, still unloading diesel. The flowrate dropped almost to zero for 3 hours with some gas being produced. A sample of this gas was taken, and Geoservice found it to be 100% methane. The flowrate began to climb again, the well was then flowed for a further 55-1/2 hours. The pressure gauges, when recovered, indicated that the well was flowing stably after about 24 hours. A certain amount of the fluctuation in the flowrate was due to the method of measurement (based on stock tank level). The well was flowing approximately 30 B/D crude oil, 24° API, with approximately 5 MSCF/D gas, gravity 0.691. Traces of sand and water were seen. Surface samples of oil were taken, then Flopetrol took their bottom hole samples on 6.7.80 after the well had produced 80 bbls; the tubing contents + rathole were 58.9 bbls. The first sample taken was discovered to contain brine. A second sample was recovered from 1438 m, then a third together with a Sperry Sun gauge to establish fluid gradients in the tubing. The results of this survey which Sperry Sun characterized as a misrun, because of the unreasonably high pressure gradients at top and bottom of the surveyd interval, are seen on Fig.I/9.7.The second and third samples were found to have good opening pressures and bubble points (opening pressures 1240 and 1470 psig, and bubble points 1500 and 1460 psig at 64° F respectively). In view of the results of the gradient survey, a tandem sampler was run to 1460 m which was considered to the lowest safe sampling point. Two further oil samples were obtained.

New Sperry Sun and Amerada pressure bombs were run, and the well was shut in for a build up survey of 18 hours. The Sperry Sun gauge failed, but the Amerada was successful and gave a stabilized bottom hole pressure of 2248 psig at 1561 m BDF. Analysis of the pressure build up indicated a formation permeability of 20 md and no skin (see Figs. I/9.8, I/9.9 and Table I/9.5). The first attempt to retrieve to bombs failed due to being unable to latch into the bombs. The well was flowed briefly to clear away sand suspected, to be on the fishing neck and F nipple. The bombs were then retrieved successfully, new bombs were run, and the well was opened on an 8/64" choke. It was flowed for 5 hours, after stabilising, with a rate slowly increasing to 43 B/D. The oil gravity (with emulsion) dropped to 15° API, and some water was produced, with the BSW rising to a peak of 24%.

The choke was increased to 16/64", and the well flowed at approximately 60 B/D. The oil gravity returned to 22° API, and the maximum BSW was 9.5%. The well was then flowed for 27.5 hours on a 1/2" choke. The flow did not stabilize, the average production over the period was 86 bpd, and on average, the production rate did not change significantly during this period, however, the bottom hole flowing pressure dropped from an initial average of 1825 psi to 1650 psi at the end. There was no evidence of water coning the BSW was generally +/- 1% with occasional peaks of 5%. Unfortunately, due to the higher rate of gas production, the meter on the surge tank could not function, and in this last flow period, the gas flow rate could not be monitored.

The well was beaned to 8/64" to recover the gauges. These has worked successfully, and the well was closed in and the test concluded.

Measurements

During flowing periods the following data were read every 15 mins (Refer Fig. I/9.5).

Well head Pressure	From dead weight tester (DWT) and Foxborough chart recorder measured at the data header
Well head temperature	From mercury thermometer in the choke manifold and Foxborough charter recorder
Annulus Pressure	From the kill line
Liquid Flow rate (B/D)	Calculated from measurements of the surge tank level
Gas Flow rate (SCF/D)	Measured with precision gas meter installed in the surge tank vent.

The latter two parameters were measured unconventionally as the very low flow rates and pressures pecluded the use of the separator.

Produced fluid densities were measured. The gas was monitored for H_2S and CO_2 content with Dräger tubes, and was also analysed on site with the Geoservice chromatograph.

During pressure build-up surveys, wellhead pressures was read

i) every 5 minutes during initial lubricator calibration stop

ii) every 15 minutes during the flow period

iii) after closing in, every 5 minutes for the first hour, then every half hour

iv) every 5 minutes during gradient stops while pulling the bombs

v) every 5 minutes during the final lubricator calibration stop

Downhole pressures were measured by Sperry Sun MRPG gauges and Ameradas. The MRPG's also recorded temperature.

Test Sequence

The test sequence may be summarized as follows:

Test Sequence

(Refer to Fig. I/9.6)

PHASE	PERIOD hrs	date	DURATION hrs	CHOKE 1/64 Ins	FLOW RATE BPD Initial	FLOW RATE BPD Final	CUM Prod. bbls	WHP psig Init.	WHP psig Final	BHP psig Init.	BHP psig Final
PERFORATED	1452	4.6.80		4	-	38	-	20	36	-	-
CLEAN UP	1744-2305	4.66.80	5.35	8	45	156	-	14	110	-	-
	2305-0515	5.6.80	6.17	4	9	72	25.8	134	125	-	-
	0515-0930	5.6.80	4.25								
	0930-	5.6.80									
	1700	7.6.80	55.50	8	72	58	105.9	125	92	-	-
BUILD UP	1700-	7.6.80									
	1100	8.6.80	18.00	-	-	-	-	92	216	1032	2248

Flowed well for 1.40 hrs (3.1 bbls) to assist in latching on to pressure

MAIN FLOW	2330-0610	8.9.80	6.67	8	35	43	119.1	82	79	2055	2042
	0610-1100	9.6.80	4.83	16	69	61	132.8	33	19	1893	1913
	1100-	9.6.80									
	1430	10.6.80	27.5	32			228.7				

Table I/9.1

MICACEOUS SAND GAS TEST

Objectives

This test was performed on the interval 1520 - 1535 m BDF, in the highly micaceous sand of lower permeability below the main, clean, section of the gas bearing reservoir. The objectives were:

a) to assess well inflow performance; permeability, skin and turbulence

b) to obtain PVT samples at separator conditions for subsequent analysis

c) to obtain atmospheric condition condensate samples

d) to obtain accurate well head composition, and liquid gas ratios using the Thornton "Minilab".

e) to obtain impurity and trace element measurements using KSLA equipment (Hydrogen sulphide, mercury, radon and water)

Test Description

A production string was run as shown in Fig.I/9.10,and the tubing was displaced to diesel through the XA-SSD prior to perforation. The surface equipment was installed as in Fig.I/9.5, the Baker sandtrap was installed during the test when it became available. The test sequence is shown in Fig. I/9.11.

After perforation, the well was opened on an 8/64" choke, to unload the diesel. After five hours it was largely flowing gas, and was passed through a 28/64" choke to the separator. The well was allowed to clean up for a further 27 hours, producing gas of gravity 0.617, and condensate of 50.3° API, with some water (mostly brine), and traces of sediment. The gas contained no detectable H_2S and approximately 0.4% CO_2.

During the last 12 hours of the clean-up period, the rate was fairly stable at +/- 5 MMSCF/D, and some preliminary sampling was done. PVT samples nos 1-3 of gas and condensate were recovered from the separator, and Thornton and KSLA did preliminary work (see results in Tables I/9.6&I/9.7).

Difficulties were experienced in running the pressure bombs due to heavy hydrate formation. Methanol was injected, and after a successful drift run the Sperry Sun and Amerada pressure bombs were installed. They remained on bottom for 6 hours recording a stable pressure of 2243 psig, corresponding to a static reservoir pressure of 2265 psia at 1527.5 m BDF.

The bombs were then pulled, and rerun with longer duration (112 hrs) clocks. The first sequential rate test was then performed, with 1-1/4 hours flow periods at rates of 1.3, 2.4, 3.4 and 5.2 MMSCF/D. However, the inflow performance was improving gradually during this test (see Table I/9.8). Thus the Darcy flow and turbulence coefficients could not be determined. The last rate was extended for 24 hours with the rate slowly increasing from 5 to 6 MMSCF/D. The WHP was also increasing. During this period Thornton took samples, (See Table I/9.6), and Geoservice made gas analyses (95% C-1, See Table I/9.9).

The well was closed in for 6 hours, for the first build up period. Analysis of the pressure buildup indicates a formation permeability of 16 md and a skin factor of 25 (76% of drawdown-including turbulence). (See Figs. I/9.12, I/9.13 and Table I/9.10).
since the well was still cleaning up during the first sequential test. The well was flowed for 4 hours at each of the following rates: 1.3, 2.4 and 3.7 MMSCF/D. Gas and condensate recombination samples no 4 were taken at the separator during the last flow rate of this test. However, it was still apparent that the inflow performance was improving during this test.

The well was closed in, and the pressure bombs retrieved. The well was then opened up for a maximum rate test. Flowing for 4-3/4 hours on a 44/64" choke, the flow rate and WHP increased considerably. After increasing the choke to 48/64" the rate and WHP continued to rise.

It had been suspected from the sequential tests, and became apparent with the last test, that the well had not cleaned up completely It was therefore decided to close the well in, and run Sperry Sun and Amerada pressure bombs before beaning the well up, in approx 1 hour stages, to its maximum flowing rate.

Thus the well was opened up and the third sequential rate test was commenced. The well was flowed for approximately 1-1/2 hours at the following rates: 16, 21, 23, 28 and 30 MMSCF/D observing for sand production with the Sand-dec probe. Each time the choke was increased there was a corresponding increase in counts from the probe, but this always returned to a base level close to zero.. At the maximum rate the adjustable choke was reduced from 104 to 92 because it exercised no control over the system at higher settings due to downstream restrictions. After 8-1/2 hours the flow rate stabilized at 32.6 MMSCF/D, and this was maintained for 3 hours. As may be seen in Table I/9.11 the inflow performance continued to improve also during this sequential test with essentially the same bottom hole flowing pressures at 16 and 32 MMSCF/D. Following the last rate the well was shut in for the second build-up period, of 9-1/2 hours.

Analysis of the pressure buildup (see Fig. I/9.14 and Table I/9.12) indicates a kh value of some 1200 mdft which is 16 times the value estimated from the first buildup. The skin factor (including turbulence) was as high as 116 (95% of drawdown). The reason for the increased kh is believed to be development of a channel behind the casing (poor cement bound log) creating communication with the better sand some 10 meters above the top of the perforations. The very high skin/turbulence could support this theory.

During the shut in period, the Baker sand trap was installed. This necessitated closing the flowhead wing valve, so that no WHP readings are available for this time. The sand trap was installed just downstream of the flowhead and sandec spool, in order not only to trap sand but also to calibrate the sandec equipment. Due to its suspected action as a separator, later confirmed, the sand trap was bypassed during Thornton's attempts at sampling. The adjustable choke, and chiksan elbows downstream showed signs of sand erosion and were replaced during the shut in period.

The well was then opened for a fourth, and final, sequential rate test.

The well was flowed:

5 hours at 9.5 MMSCF/D
9 hours at 18.1 MMSCF/D
4½ hours at 27.5 MMSCF/D

Analysis of this sequential test (see Fig.I/9.15 and Table I/9.13) indicates that turbulence effects are very significant. Combined with results from the second buildup it is found that at 32.6 MMSCF/D (rate prior to buildup) some 78% of the total drawdown is caused by turbulence. Out of the total skin factor of 116 seen in the buildup only 23.5 is Darcy skin. The remainder is turbulence. Only 5% of the drawdown corresponds to Darcy flow drawdown on the formation.

The second flow period was extended to allow Thornton to take more samples. However, there were severe hydrate problems. The well had to be closed in suddenly when the line from the separator to the gas flare plugged and the separator pressure rose sharply. This was due, in part, to an inadequate steam supply to the heater, which was improved gradually during the course of the tests. There were further hydrate problems, some of which seemed to emanate from the Thornton manifold itself. Injection of methanol controlled the problem, but can have a deleterious effect on the Thornton sampling procedure.

PVT recombination samples nos 5-8 were taken at the separator during this sequential rate test. Geoservice also analysed gas samples. (see Fig. I/9.9).

The well was then beaned up to its maximum rate, and the flow was stable at 31.2 MMSCF/D for 1-1/2 hours, indicating that no further cleaning up had occurred.

The well was then closed in for a 2 hour build up period (the Sperry Sun gauge reached the end of its clock and the test was concluded. As can be appreciated from Fig .I/9.6 and Table I/9.14 this buildup was essentially identical to the second buildup. The kh was estimated at 11500 mdft and the skin factor (including turbulence) at 112.

Measurements

During the test, WHP, WHT etc were measured as detailed for the Oil Zone Test. In addition, since flow was passed through the separator, the gas flow rate was measured every 15 minutes with a Daniel orifice meter, and the liquid production rate was calculated by periodically reducing the level of condensate in the separator to a set level, by flowing into the stock tank, and measuring the volume. Sand production was monitored with the sandec probe, (see separate report). Only one probe was used, and gave only qualitiative results, because no correlation between signal and sand production was available. In addition, H_2S, CO_2 and salinity were monitored during flow periods.

Test Sequence

The test sequence can be tabulated as follows:

Table I/9.2

[illegible] AND GAS TEST

Test Sequence (see fig. [illegible]/9.13)

Phase	Period	Duration hrs	Choke 1/64 ins	Flowrate MMSCF/D Initial	Flowrate MMSCF/D Final	Cumulative Production MMSCFw	WHP psig Initial	WHP psig Final	[illegible]HP psig Initial	[illegible]HP psig Final	Separator Pressure psig
CLEAN UP	0845-1400 15.6.80	5.25	+/-15	-	-	-	50	990			
	1400-1700										
	15-16/6.80	27.0	23	1.92	5.03	+/-4.8	588	1152			
Hydrates formed in the tubing prevented running pressure bombs (lost 10 hours)											
STATIC PRESSURE MEASUREMENT	0712-1300 17.6.80	5.3	-	-	-	-	1949	1948	2241	2243	
SEQUENTIAL RATE TEST 1	0345-0500 18.6.80	1.25	12	1.27	1.30		1859	1599	2152	2028	400
	0500-0615 -	1.25	18	2.37	2.33		1514	1370	1841	1776	450
	0615-0730	1.25	23	3.48	3.36		1134	1200	1453	1525	455
	0730-0730										
	18/19-6.80	24.0	28	5.00	6.11	10.7	1040	1254	1259	1459	475
1st BUILD UP	0730-1330 19.6.80	6.0	-	-	-		1254	1988	1459	2264	
SEQUENTIAL RATE TEST 2	1330-1530	2	12	1.32	1.32		1885	1882	2150	2145	195
	CLOSED IN FOR HELICOPTER										
	1600-1800	2	12	1.23	1.29		1935	1892	2156	2145	135
	1800-2200	4	18	2.36	2.38		1732	1728	1992	2011	450
	2200-0200 20.6.80	4	20	3.68	3.73		1540	1555	1795	1828	465
MAX FLOW RATE TEST	0845-1330	4.75	44	10.87	12.63		909	1112	-	-	[illegible]
	1530-1745	4.25	48	15.63	15.85		1010	1040	-	-	[illegible]
SEQUENTIAL RATE TEST 3	0430-0600 21.6.80	1.50	48	15.86	16.01		1014	1022	[illegible]	1293	[illegible]
	0630-0730	1.00	60	20.32	20.98		829	1179	[illegible]	[illegible]	[illegible]
	0800-1000	2.00	72	23.00	23.01		754	754	[illegible]	[illegible]	[illegible]
INCREASED TO MAX FLOW RATE	1000-1130	1.50	78	26.15	26.27		547	537	1092	[illegible]	[illegible]
	1200-1330	1.50	90	26.66	29.46		597	632	[illegible]	[illegible]	[illegible]
	1330-1500	1.50	104	28.38	28.64		600	614	[illegible]	[illegible]	250
	1500-0230 22.6.80	11.50	92	27.57	32.62	40.16	594	589	[illegible]	[illegible]	[illegible]
2nd BUILD UP	0230-1200	9.50	-	-	-		589	1987	[illegible]	[illegible]	-
SEQUENTIAL RATE TEST 4	1000-1315	5.25	28	9.51	9.53		1347	1345	[illegible]	[illegible]	[illegible]
	[illegible] Closed well in when hydrates plugged flare line										
	2100-0600 23.6.80	9.00	40	18.51	18.1		1510	1502	[illegible]	[illegible]	[illegible]
	[illegible]5-1245	4.50	54	27.24	27.50		1105	1095	[illegible]	[illegible]	[illegible]
INCREASED TO MAX FLOW RATE	1415-1515	1.00	96	31.29	31.23		579	530	[illegible]	[illegible]	[illegible]
	1530-1800	2.50	123	32.14	31.22	57.5	532	529	[illegible]	[illegible]	[illegible]
3rd BUILD UP	1800-2300	5.00	-	-	-		529	1989	[illegible]	[illegible]	-

CLEAN SAND GAS TEST

Objectives

This test was carried out on the interval 1435-1460 m BDF, in the so-called "clean" sand, a zone of unconsolidated gas-bearing sand, containing little mica and having a very high permeability. The objectives of the test were:

a) to evaluate well inflow performance; skin and turbulence
b) to assess sand influx, and gravel pack efficiency
c) to obtain PVT recombination samples at separator conditions
d) to obtain atmospheric condensate samples
e) to allow Thornton to measure accurate well head compositions and liquid/gas ratios
f) to allow KSLA to perform trace element analyses.

Test Description

After the micaceous sand zone was squeeze cemented, the clean sand was perforated in viscous brine, to prevent losses. The perforations were then backsurged. Mechanical difficulties were encountered, and after the final attempt 84 bbls of viscous brine were lost to the formation. The wire wrapped screen liner was then run and gravel packed with + 6000 lbs of 20-40 mesh gravel in a "Water-Pack" slurry. The production string was run (see Fig. I/9.17), but due to a delay in the "breaking" of the "Water-Pack" carrier fluid, it was decided to acidize the well prior to production. This was performed as part of the operation of displacing the tubing string to diesel, 20 bbls of 15% and hydrochloric acid were pumped into the formation.

The well was then opened and the test commenced. The test sequence is illustrated in Fig. I/9.18.

The choke size was slowly increased to unload the well. After 3/4 of an hour 48 Bbls of diesel had been produced back and gas broke through. The well was then flowed on a 33/64" choke for 17 hours. The pH of the liquids produced was monitored, and remained low as the acid returned. The well was beaned up as to 40/64" and the clean up continued for another 11 hours. At the end of this period, liquid produced by the well was still 60% acid/brine. The gas had the same composistion as the previous test (95% C-1, see Fig. I/9.15) and no H_2S was detected with the Dräger tubes.

The well was then flowed at 23 MMSCF/D for 4 hours. The flow was fairly stable, but acid and brine were still being produced. The well was then beaned up in stages until fully open. A maximum rate of nearly 40 MMSCF/D was achieved for about 11 hours, giving a total of about 48 hours clean up. By that time 75% of the liquid produced was condensate, but some acid was still being produced.

KSLA performed some preliminary sampling, but the well stream was still contaminated.

The well was closed in, and Sperry Sun and Amerada pressure bombs were run. Due to the threat of impending industrial action, the test programme was condensed at this point, to enable it to be completed before 10th July. The well was beaned up to its maximum rate and flowed for 4 hours at 41 MMSCF/D. Atmospheric pressure samples of condensate were recovered from the separator. The well was then closed in for the first pressure build up survey. It was observed that the pressure built up very rapidly, stabilising after about five minutes. Although 1 minute mode Sperry Sun gauges were used the buildup was too quick to quantitively determine the value of kh (see Fig.I/9.19) It is, however, obvious, in view of the extremely quick buildup of the 640 psi drawdown, that the values of kh and skin/turbulence were both very high.

The well was then flowed again at its maximum rate, 40 MMSCF/D, for 5 ½ hours. Flow was passed through the Thornton mainifold, causing a noticeable drop in production rate, and Thornton took samples.

The well was closed in for the second pressure build up of 1 ½ hours. Since the Sperry Sun gauges were on a 2 minute mode, this provided insufficient resolution for interpretation of the very rapid build up.

New 1 minute mode Sperry Sun gauges were run, and the sequential rate test was performed.

The well was flowed:

1 1/4 hrs at 9.6 MMSCF/D
6 hrs at 21.0 MMSCF/D
1 1/4 hrs at 30.6 MMSCF/D
1 1/2 hrs at + 38 MMSCF/D (maximum rate)

The second flow period was extended to allow Thornton and KSLA to take samples (See Tables I/9.16&I/9.17 for results). PVT recombination samples nos. 1 through 8 of gas and condensate were taken at the separator.

After maximum flowrate period , the well was shut in for the third pressure build-up. The bombs were recovered, and it was found that both Sperry Sun gauges had failed, and only the Amerada gauge had worked. This did not have sufficient time and pressure resolution to draw conclusions from this buildup data.

However, the Amerada pressures provided useful information for interpreting the variable rate test. (See Fig. I/9.20 and Table I/9.18).As may be appreciated from th resulting inflow performance relationship in Fig. I/9.21, almost 100% of the drawdown is used to overcome the severe turbulence. Assuming no Darcy skin the minimum value of the formation permeability was estimated at 1.7D. However, with the very high turbulence, it is reasonable also to assume a high Darcy skin factor and thus a much higher permeability.

The maximum flow rate achieved, of ca. 40 MMSCF/D, was considerably less than had been expected. With the severe turbulence it was suspected that, despite the backsurging and acidisation some of the perforations might be plugged. A PCT was run, consisting of a flow meter, high resolution thermometer and casing collar locator. After two misruns, in which the CFS, continuous flow-meter sonde, failed, the full bore spinner was run and functioned successfully. With the well flowing at 24.4 MMSCF/D, the flow meter indicated a flow profile as illustrated in Fig. I/9.22. The results can be tabulated as follows:

1436-1442	ca. 50	clean, highly permeable sand
1442-1450	ca. 10	deteriorating permeability, highly micaceous in parts
1450-1457	ca. 35	top 5m: deteriorating permeability some limestone streaks bottom 2m: good, highly permeable sand
1457-1460	ca. 5	good highly permeable sand

Thus, the perforations were found to be not producing equally, with half of the flow coming from the top 6m. This profile does not correspond closely with the lithological differences seen, and appears to indicate plugging of the perforations at the bottom of the interval.

The HRT shows an anomalous temperature gradient in the interval, and yields no useful information.

In order to gain better build up information, two Sperry Sun gauges were run, one in a 15 second mode, the other in a 30 second mode. The well was then flowed for:

1 hour at 20.7 MMSCF/D
1 hour at ± 39 MMSCF/D

This was followed by a 3 hour pressure build up survey, and the gauges were recovered. The 15 second mode gauge had failed, but the other functioned.

The two rate test gave similar BHFP's to those obtained in the previous four rate test. The buildup was extremely fast (essentially fully built up in 3 minutes). A McKinley type curve plot of the buildup is shown in Fig. I/9.23 However, there is no type curve of high enough transmissibility to fit the data. As explained in Table I/9.19,however, it is believed that the formation permeability may be as high as 8 Darcies.

The test was then concluded prior to the outset of industrial action.

Measurements

Measurement during the test were as described under the Micaceous Sand Gas Test.

Test Sequence

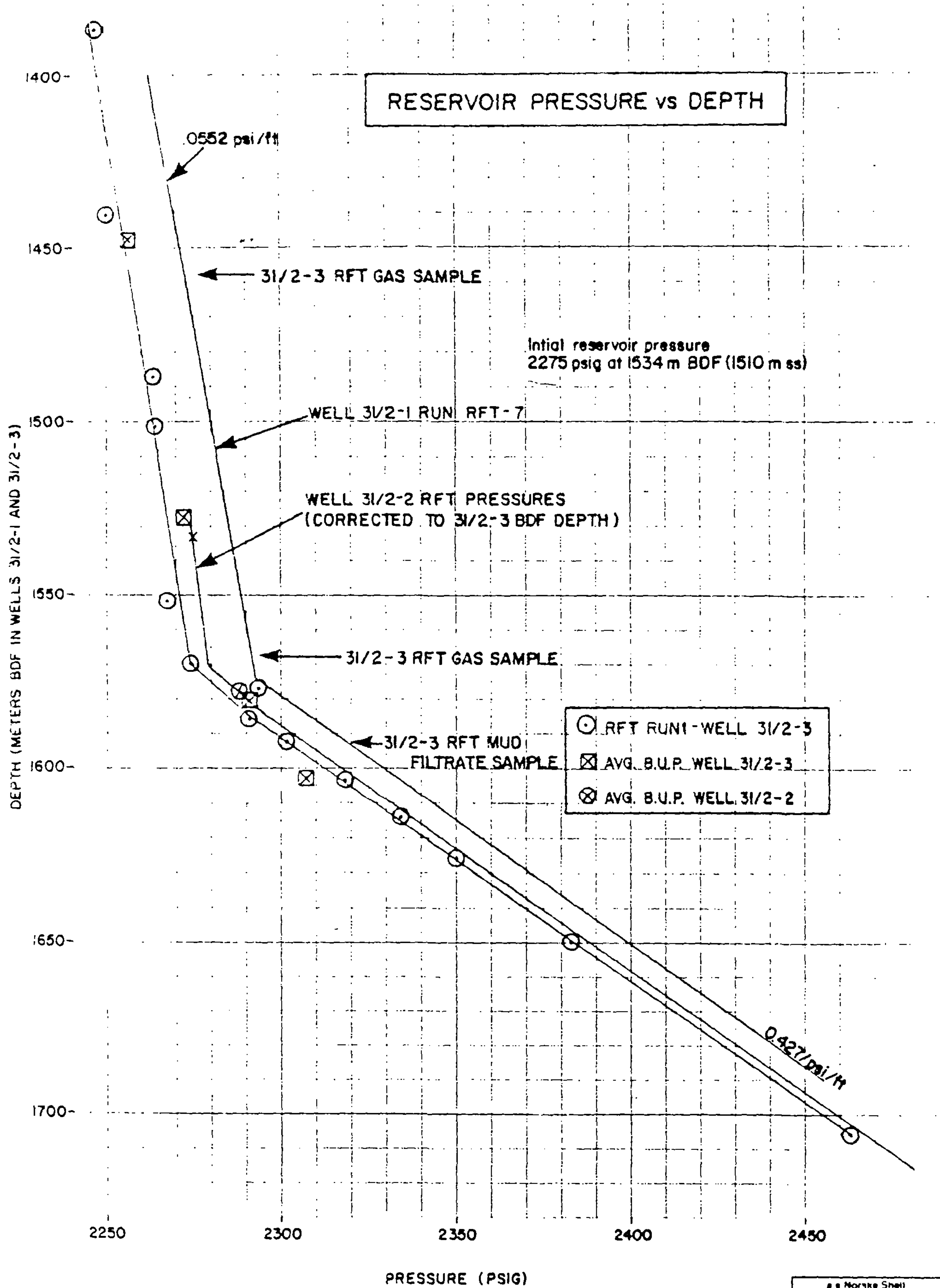
The Test sequence can be tabulated as follows:

CLEAN SAND GAS TEST SEQUENCE

PHASE	PERIOD		TIME HRS	CHOKE INSX1/64	FLOWRATE MMSCF/D Init.	FLOWRATE MMSCF/D Final	CUM PROD MMSCF	WHP psig Init.	WHP psig Final	BHP psig Init.	BHP psig Final	SEPARATE PRESSURE psig
CLEAN UP	0800	4.7.80	16	32	11.99	11.61		1829	1879	-	-	290
	0400-	5.7.80										
	0400-1500		11	40	16.93	17.07		1789	1783	-	-	300
	1500-2000		5	48	23.07	22.9		1652	1652	-	-	440
	2000-2200		2	56	27.96	28.74		1477	1480	-	-	440
	2200-0100	6.7.80	3	96	38.10	38.10		977	990	-	-	370
	0100-1230		11.5	MAX	39.92	39.52		732	782	-	-	345
MAX FLOW RATE	1750-2220		4.5	MAX	40.82	40.70	54.5	780	790	1655	1612	350
1st BUILD UP	2220-0400	7.7.80	5.67	-	-	-		790	1997	1612	2254	-
MAX FLOW RATE	1000-1530		5.5	MAX	41.42	39.12	63.7	794	770	1693	1681	350
2nd BUILD UP	1530-1700		1.5	-	-	-	-	770	2002	1681	2254	-
SEQUENTIAL FLOW	2200-2315		1.25	32	9.65	9.67		1954	1952	2227	2226	315
RATES TEST 1	2315-0515	8.7.80	6.0	46	21.19	20.69		1760	1757	2121	2109	330
	0515-0630		1.25	60	30.62	30.62		1484	1484	1967	1961	340
	0630-0800		1.5	MAX	39.61	35.85	73.3	889	800	1719	1748	360
3rd BUILD UP	0800-1100		3.0	-	-	-		800	2001	1748	2256	-

Schlumberger ran a Production Combination Tool : flowmeter and high resolution thermometer. Due to troubles with the flowmeter it was rerun twice.

PHASE	PERIOD		TIME HRS	CHOKE INSX1/64	FLOWRATE MMSCF/D Init.	FLOWRATE MMSCF/D Final	CUM PROD MMSCF	WHP psig Init.	WHP psig Final	BHP psig Init.	BHP psig Final	SEPARATE PRESSURE psig
PCT RUN	0008-0130	9.7.80	1.	48	24.18	24.18		1694	1670	-	-	
2 RATE	0600-0700		1.	46	20.68	20.65		1772	1774	2144	2139	315
FLOW TEST	0700-0800		1	MAX	40.85	38.09	76.8	800	727	1774	1789	330
4th BUILD UP	0800-1100		3	-	-	-		727	2002	1789	2254	-



a s Norske Shell

31/2-3

EXPLORATION WELL RESUMÉ

RESERVOIR PRESSURE VS DEPTH

EPPP/22 FIG I/91

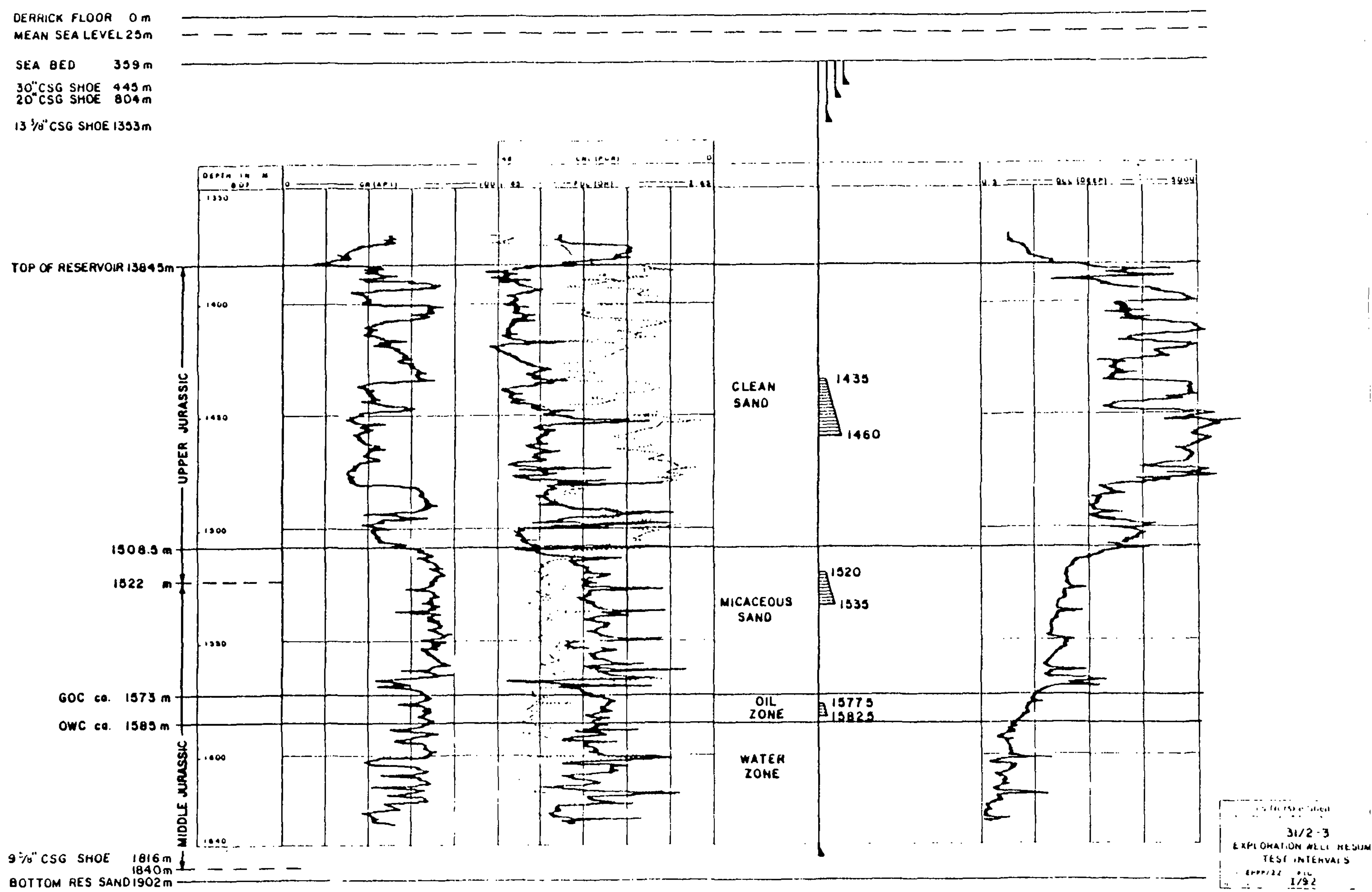
WELL 31/2-3

SAMPLES OBTAINED FROM RFT TESTS

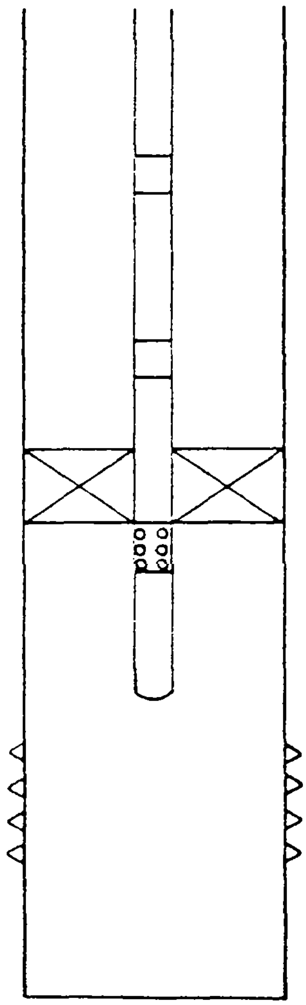
Test No.	Depth m-BDF	Recovery	Remarks
4.1	1458	Gas	2-3/4 gal chamber sent to laboratory for conventional gas PVT analysis with composition to C20+
6.11	1568.5	Gas	As for test No. 4.1
10.1	1584.5	Mud Filtr. + Sand	Piston in sample chamber jammed because of sand influx
1.2	1592.7	Mud Filtr.	Resistivity measurement indicates mud filtrate
9.11	1593	Mud Filtr.	As for test No. 1.2

Table I/9.4

WELL 31/2-3
TEST INTERVALS



31/2-3 DRILL STEM TEST ASSEMBLY



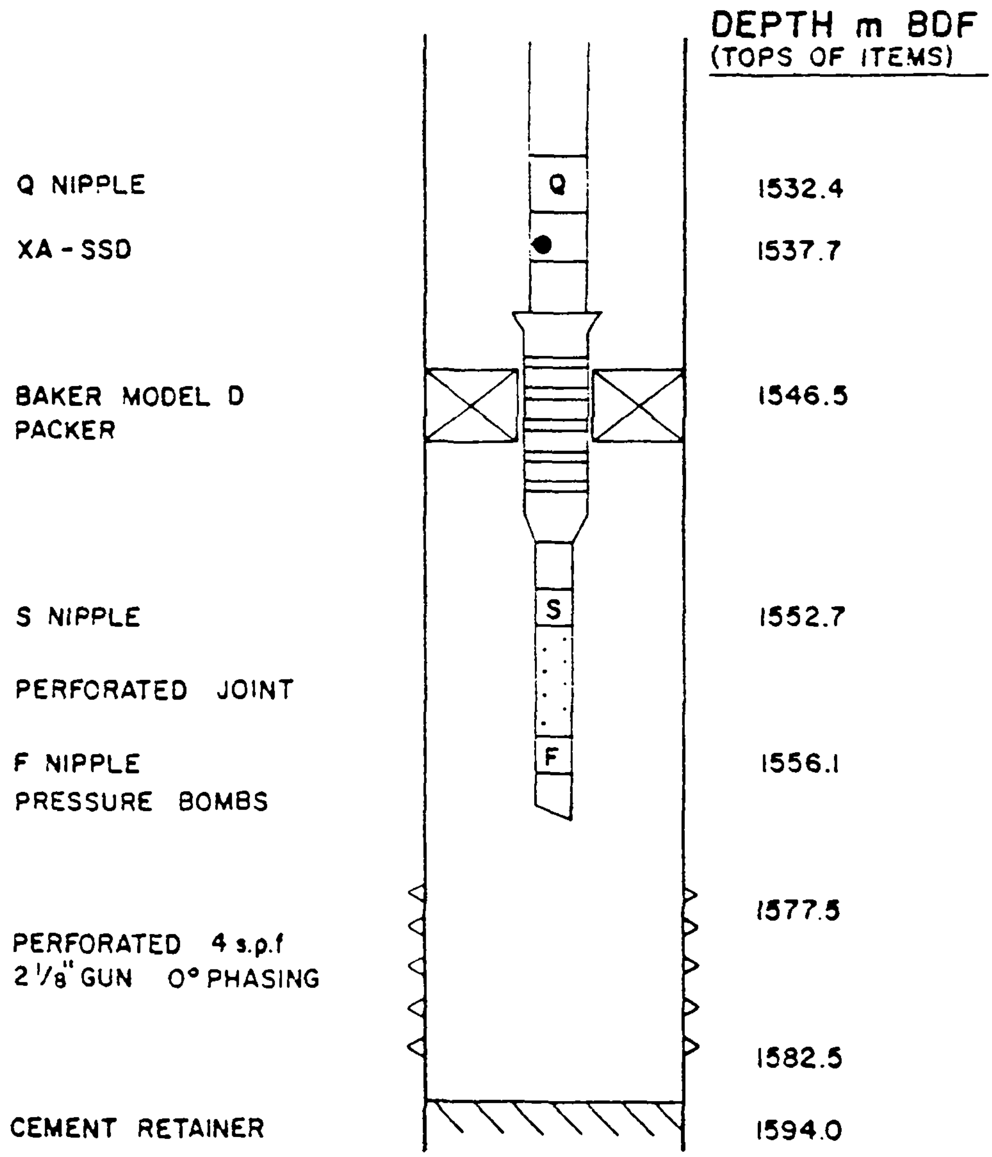
	DEPTH m BDF
FULL-FLO TESTER VALVE	1523.6
90' DRILL COLLAR SAMPLE CHAMBER (CAP 87.5 L)	
APR-N VALVE	1565.5
RTTS PACKER	1574.0
PERFORATED NIPPLE	
BT PRESSURE GAUGES	1576.0
RPG PRESSURE GAUGES	1583.0
	1585.8
	1600.5
PERFORATED INTERVAL	
	1605.0

a.s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3
EXPLORATION WELL RESUMÉ
DRILL STEM TEST
TEST ASSEMBLY

EPPO/3 I/93

31/2-3 OIL ZONE PRODUCTION TEST ASSEMBLY



a.s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3

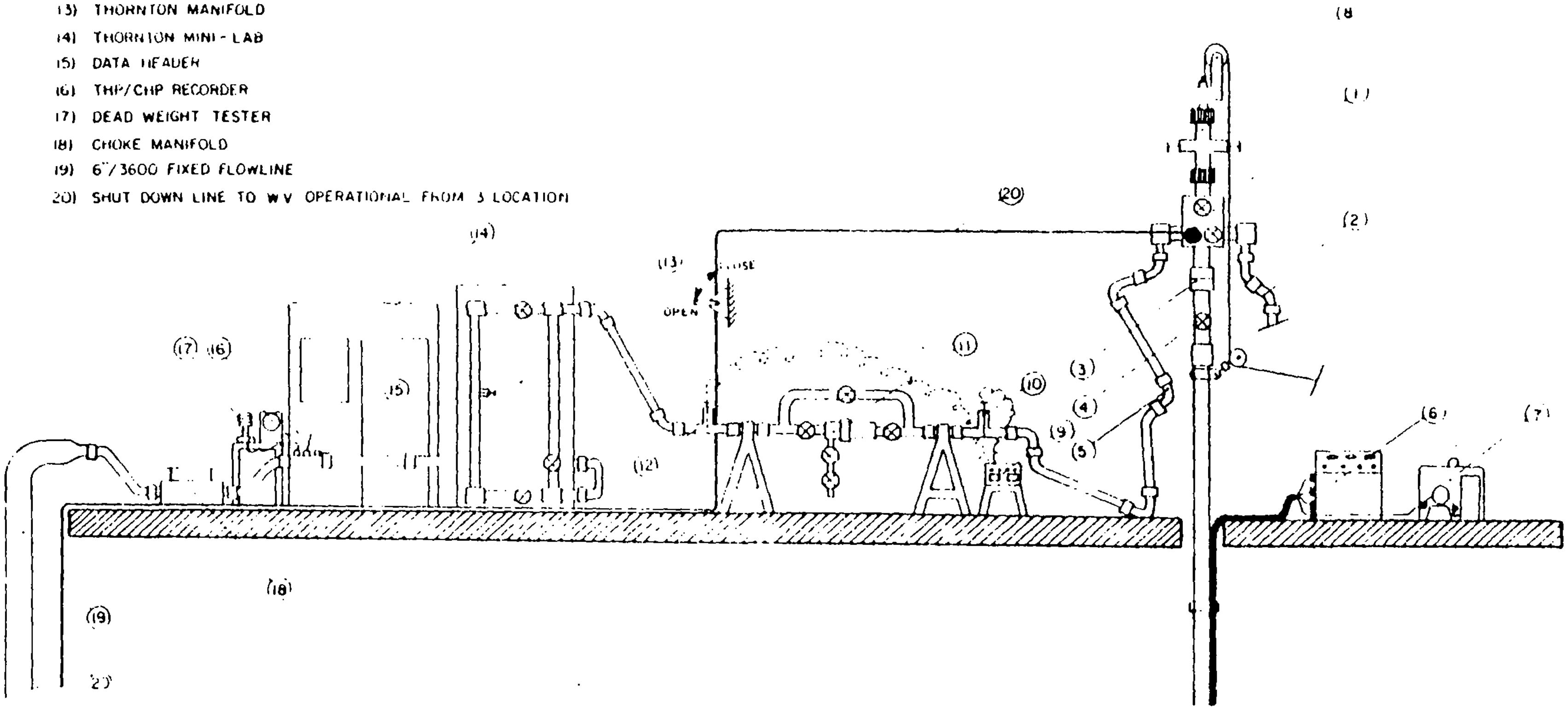
EXPLORATION WELL RESUMÉ
OIL ZONE TEST
TEST ASSEMBLY

AUTHOR EPPO/3 | FIG I/34 | DATE
REPORT NO | | DRAW NO

WELL TEST ARRANGEMENT ON DRILLFLOOR

(BORGNY DOLPHIN)

1) FLOPETROL WELL HD + AUT WINGVALUE
2) KILL LINE COMPLETE WITH BPV
3) SWIVEL
4) MASTERGATE, HAND-OPERATED
5) 3"/1502 CHICKSAN LOOPS
6) LUBRICATOR VALVE AND E Z THEE CONTROL PANE..
7) GLYCOL INJECTION PUMP
8) WIRELINE BOP + STUFFINGBOX
9) "SANDEC" SAND DETECTOR / MONITOR
10) SAND PROBE + HOUSING
11) BAKER KNOCK-OUT SANDFILTER + BY PASS + DRAIN
12) SANDPROBE HOUSING
13) THORNTON MANIFOLD
14) THORNTON MINI-LAB
15) DATA HEADER
16) THP/CHP RECORDER
17) DEAD WEIGHT TESTER
18) CHOKE MANIFOLD
19) 6"/3600 FIXED FLOWLINE
20) SHUT DOWN LINE TO W V OPERATIONAL FROM 3 LOCATION

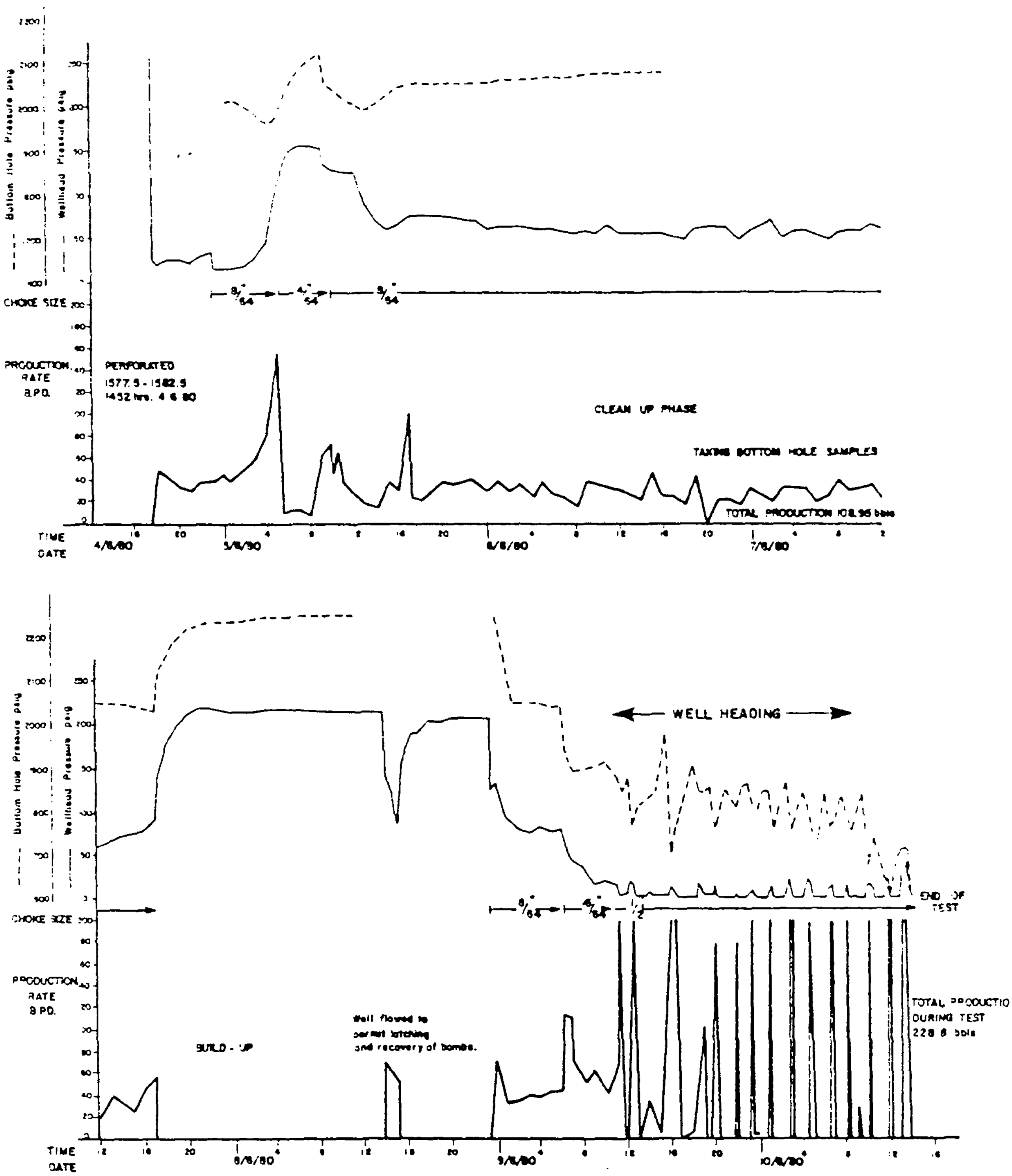


a-s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3
EXPLORATION WELL RESUMÉ
WELL TEST ARRANGEMENT
ON DRILLFLOOR

FIG.
I/9.5

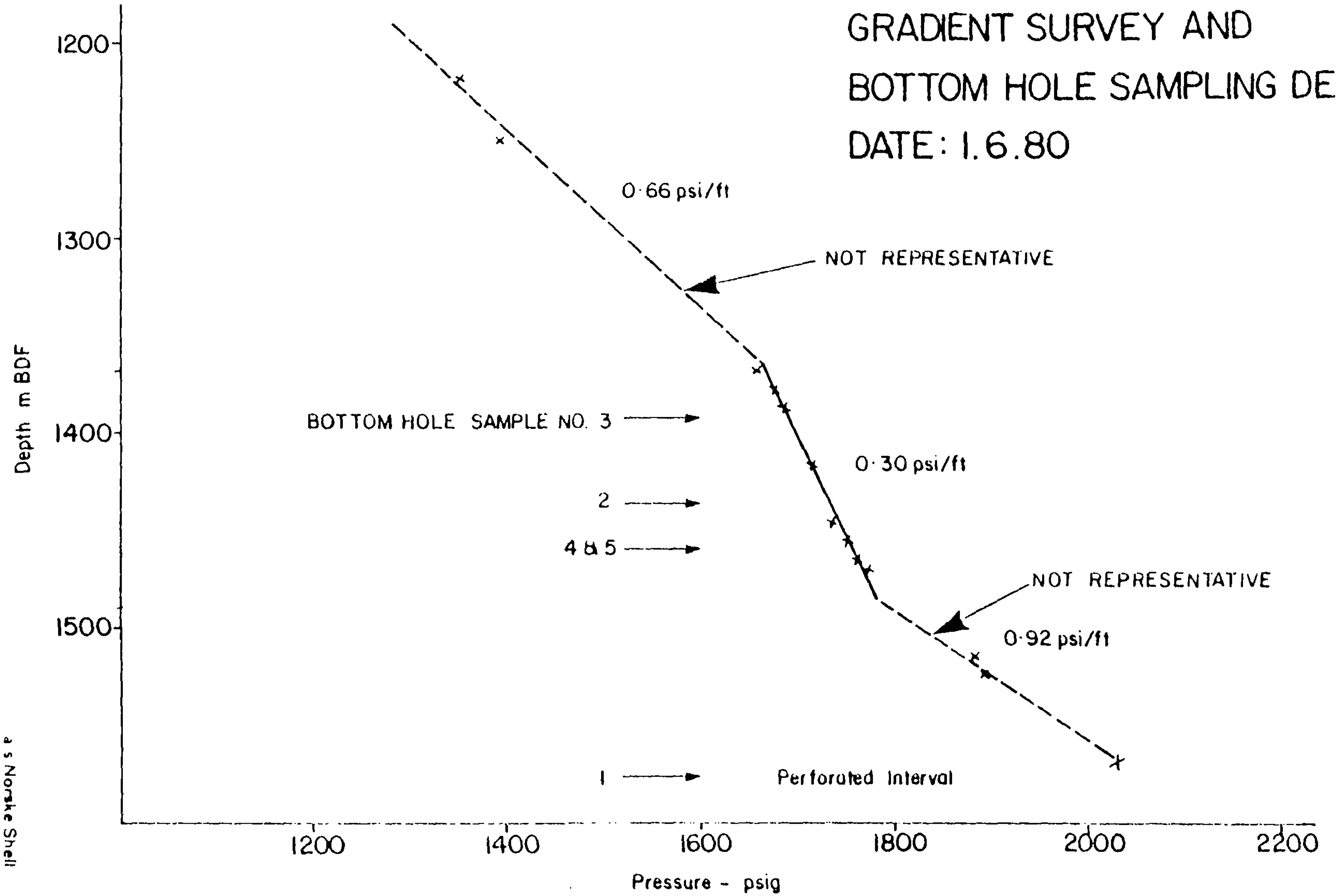
WELL 31/2-3 OIL ZONE PRODUCTION TEST
TEST SEQUENCE



a·s Norske Shell EXPLORATION & PRODUCTION FORUS	
31/2 - 3 EXPLORATION WELL RESUMÉ OIL ZONE TEST SEQUENCE	
AUTHOR EPPO/5	FIG. I/9.6
REPORT NO	DATE / DRAW NO

31/2-3 OIL ZONE TEST GRADIENT SURVEY AND BOTTOM HOLE SAMPLING DEPTHS

DATE: 1.6.80



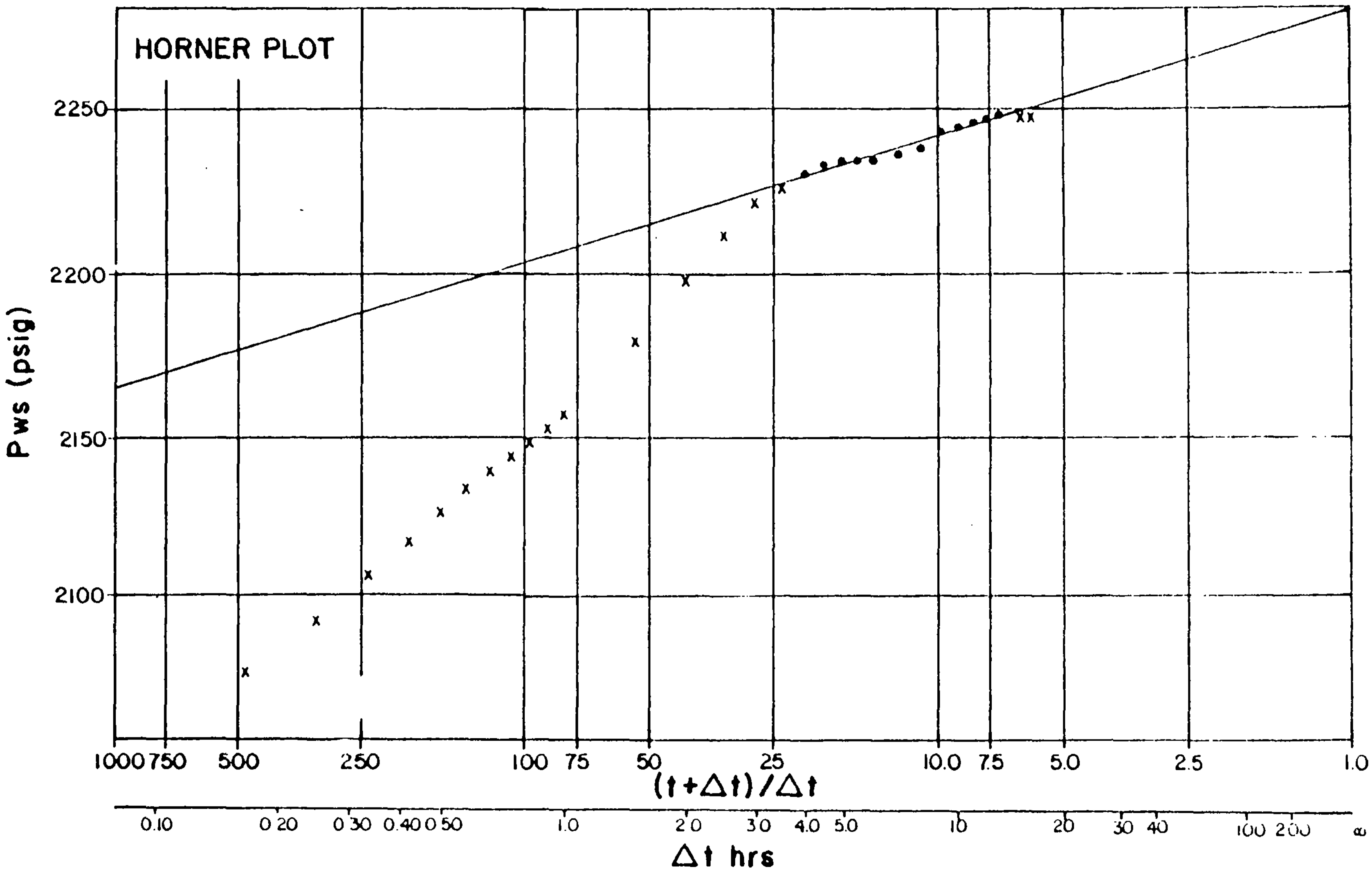
a.s Norske Shell

31/2-3

EXPLORATION WELL RESUMÉ

OIL ZONE TEST GRADIENT SURVEY

FIG I/9.7

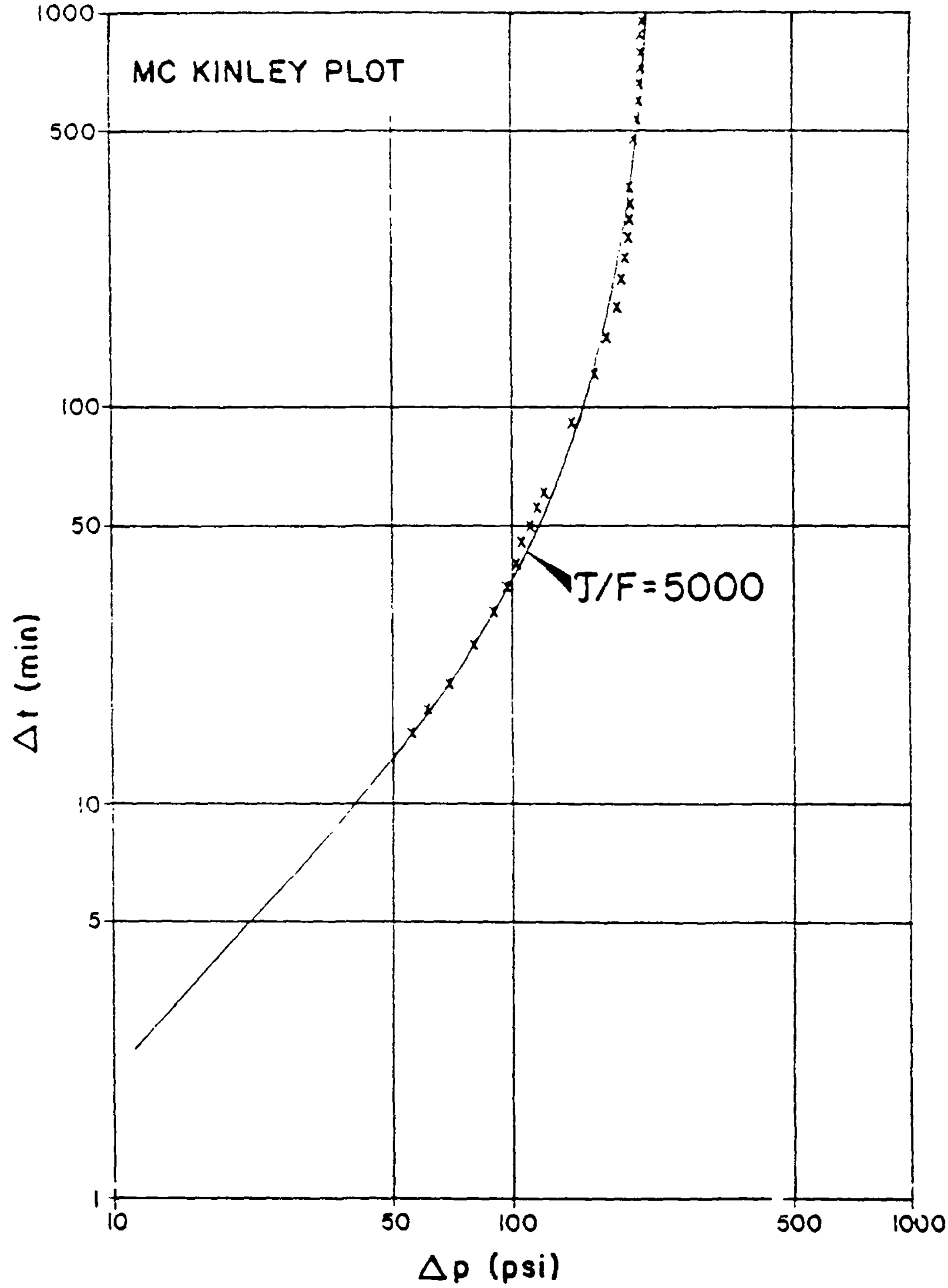


●●● POINTS CHOSEN FOR SEMI - LOG STRAIGHT LINE
WELL 31/2-3 OIL ZONE TEST 1577.5 - 82.5M BUILD UP 7.6.80

a/s Norske Shell
EXPLORATION & PRODUCTION

31/2-3
EXPLORATION WELL RESUMÉ
HORNER PLOT
OIL ZONE TEST BUILDUP

EPPP/22 FIG I/9.8



WELL 31/2-3 OIL ZONE TEST 1577.5-82.5M BUILD UP 7.6.80

a/s Norske Shell

31/2-3
EXPLORATION WELL RESUMÉ
MC KINLEY PLOT
OIL ZONE TEST BUILDUP

EPPP/22 FIG I/99

31/2-3 OIL TEST

PRESSURE BUILD UP INTERPRETATION

PARAMETERS

Well bore radius	r_w = 0.51 ft
Thickness (perforated length)	h = 16.5 ft
Porosity	$\emptyset$ = 0.30
Reservoir Pressure	p = 2248 psig at 1561 m BDF
FBHP before shut in	p_{wf} = 2036 psig at 1561 m BDF
Oil rate before shut in	q_o = 32 STB/D
Cumulative production	N_p = 106 STB
Formation volume factor	B_o = 1.1
Total compressibility	$c_t = 23 \times 10^{-6}$/psi
Oil viscosity	μ_o = 2.5 cp

HORNER ANALYSIS (See Fig. 9)

Straight line slope	m = 39.2 psi/cycle
Permeability thickness	kh = 365 mdft
Permeability (h= perforated length)	k = 22.1 md
Extrapolated pressure	p* = 2281 psig
Pressure after 1 hr shut in	p_{1hr} = 2206 psig
Skin factor	S = 1.0
Pressure drop due to skin	Δps = 35 psi (17% of drawdown)

MCKINLEY TYPE CURVES (See Fig. 10)

Match obtained for : $T/F = 5000$

Match point $\Delta p = 100$ for $\Delta pF/q_oB_o = 7.6 \times 10^{-2}$

Then $F = (\Delta pF/q_oB_o) \times \dfrac{q_oB_o}{\Delta p} = 7.6 \times 10^{-2} \times \dfrac{32 \times 1.1}{100} = 26.8 \times 10^{-3}$

Transmissibility $T = (T/F) \times F = 5000 \times 26.8 \times 10^{-3} = 134$ mdft/cp

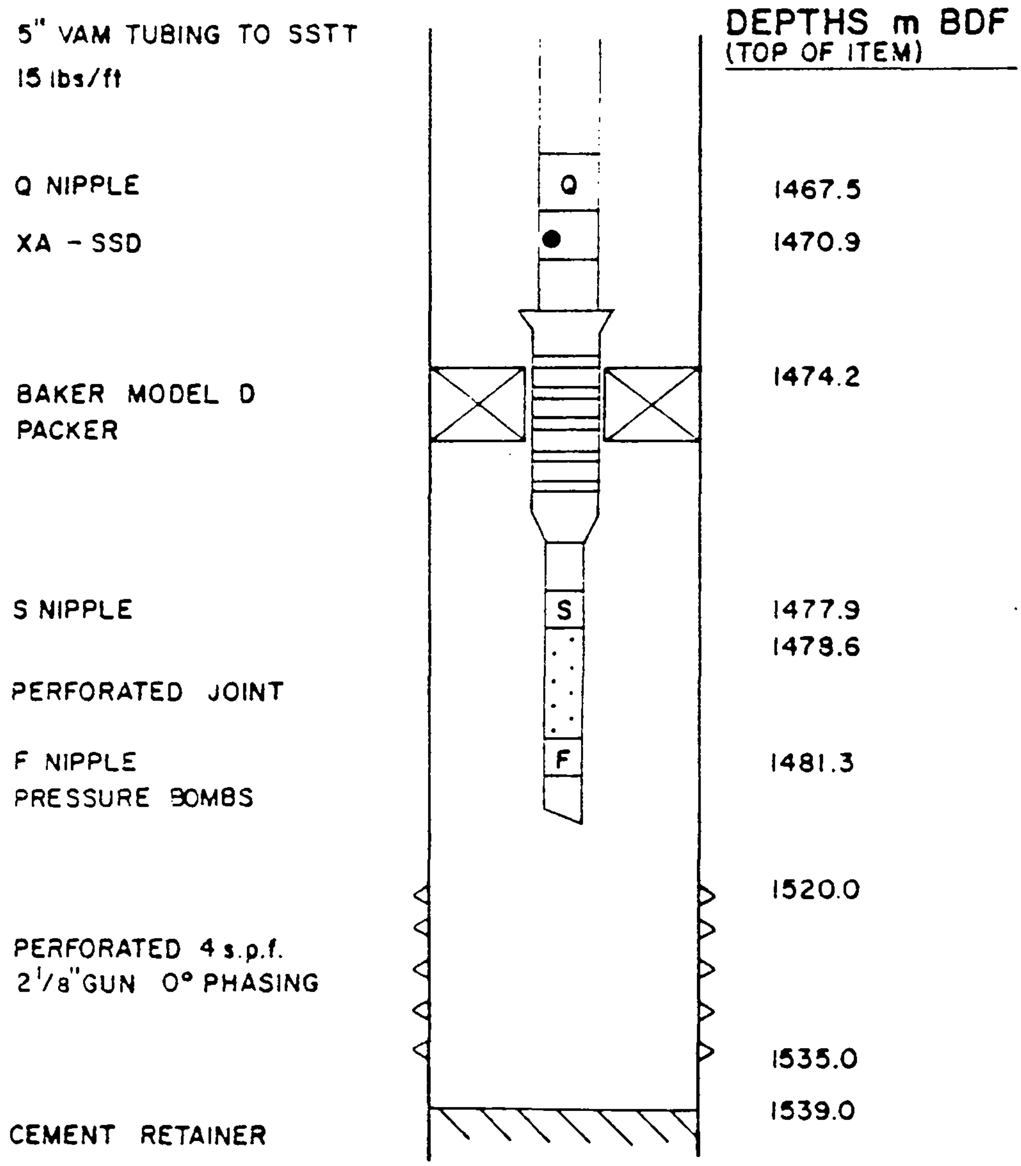
Permeability thickness $kh = T \times \mu_o = 134 \times 2.5 = 334$ mdft

Permeability $k = \dfrac{kh}{h} = \dfrac{334}{16.4} = 20$ md

Since all points fit one type curve there is no skin

Table I/9.5

31/2-3 MICACEOUS SAND GAS TEST ASSEMBLY



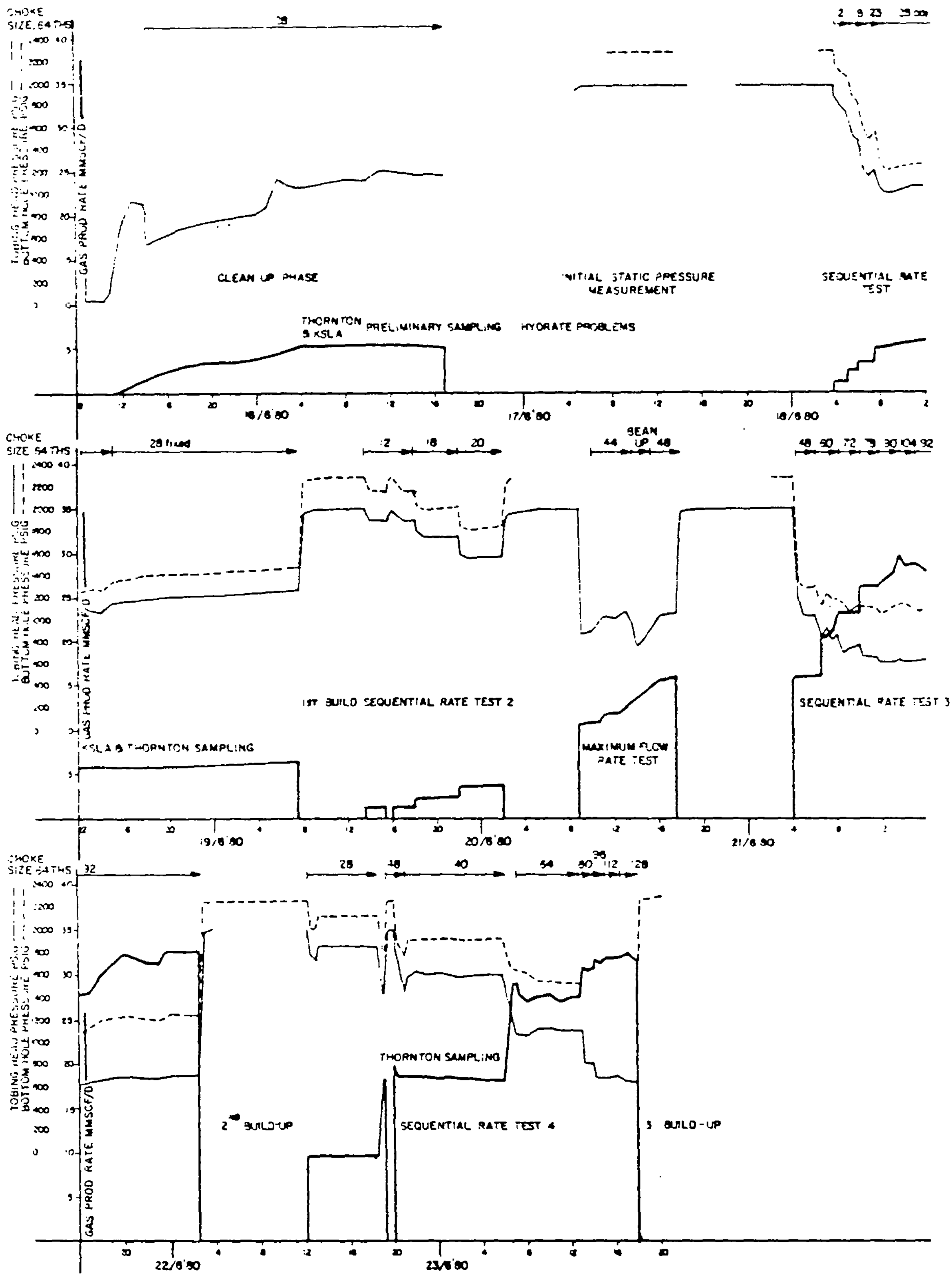
a-s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3

EXPLORATION WELL RESUMÉ
MICACEOUS SAND GAS TEST
TEST ASSEMBLY

EPPO/3 FIG I/910

WELL 31/2-3 MICACEOUS SAND GAS TEST
TEST SEQUENCE



a·s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3

EXPLORATION WELL RESUMÉ
MICACEOUS SAND GAS TEST
TEST SEQUENCE

AUTHOR EPPO/3	FIG.	DATE
REPORT NO	I/9.11	DRAW NO

THORNTON RESULTS

The results below are provisional and based upon telexes received from the rig, the final Thornton report was not available at the time of writing. Due to the industrial action on the rig in July/August the samples taken could not be despatched from the rig.

DATE	TIME	STAGE 1			STAGE 2		
		Pressure psig	Temp °C	CGR Bbl/MMScf	Pressure psig	Temp °C	CGR Bbl/MMSc
16.6.80	1130-1245	1000	4.5	4.0	500	-15.3	1.44
18.6.80	1400	1000	4.2	3.54	500	-15.3	1.58

Further sampling attempts were made at CGR's of up to 7 BBL/MMSCF. However, in view of the problems encountered with hydrates and methanol/glycol injection these results are felt not to be reliable.

TABLE I/9.6

MICACEOUS SAND GAS TEST

KSLA RESULTS

The results below are provisional and based on telexes received from the rig during the test. The final report from KSLA had not been received at the time of writing. Analyses were performed on gas phase samples taken from the separator. The water content was monitored at the well head.

Date	Time	H_2S ml/m^3	Hg mg/m^3	Rn pico curie	H_2O in sep. gas % by vol	H_2O in well stream % by vol
16.6.80	0830	0.01				
	0900	0.04				
	0945					0.72
	1140	0.05	0.026			
	1330	0.05	0.096	5.5		
	1400		0.126*			0.03
	1515	0.05				
18.6.80	1045				0.118	
	1315	0.09	0.03			
	1400					0.02
	1500	0.09	0.01			0.02
	1600			5.2		
	1700	0.09	0.03		0.066	
	2100	0.09	0.01			
	2145	0.10	0.01			
	2330	0.10	0.01		0.092	
19.6.80	0200	0.10	0101			
	0500	0.11	0.01			

* Certain abnormal mercury levels might be ascribed to simultaneous taking of PVT samples from the separator, a process also using mercury, e.g. PVT sample 1 was taken 1320 - 1405 hrs, coinciding exactly with the high Hg reading.

Table I/9.7

MICEACEOUS SAND GAS TEST

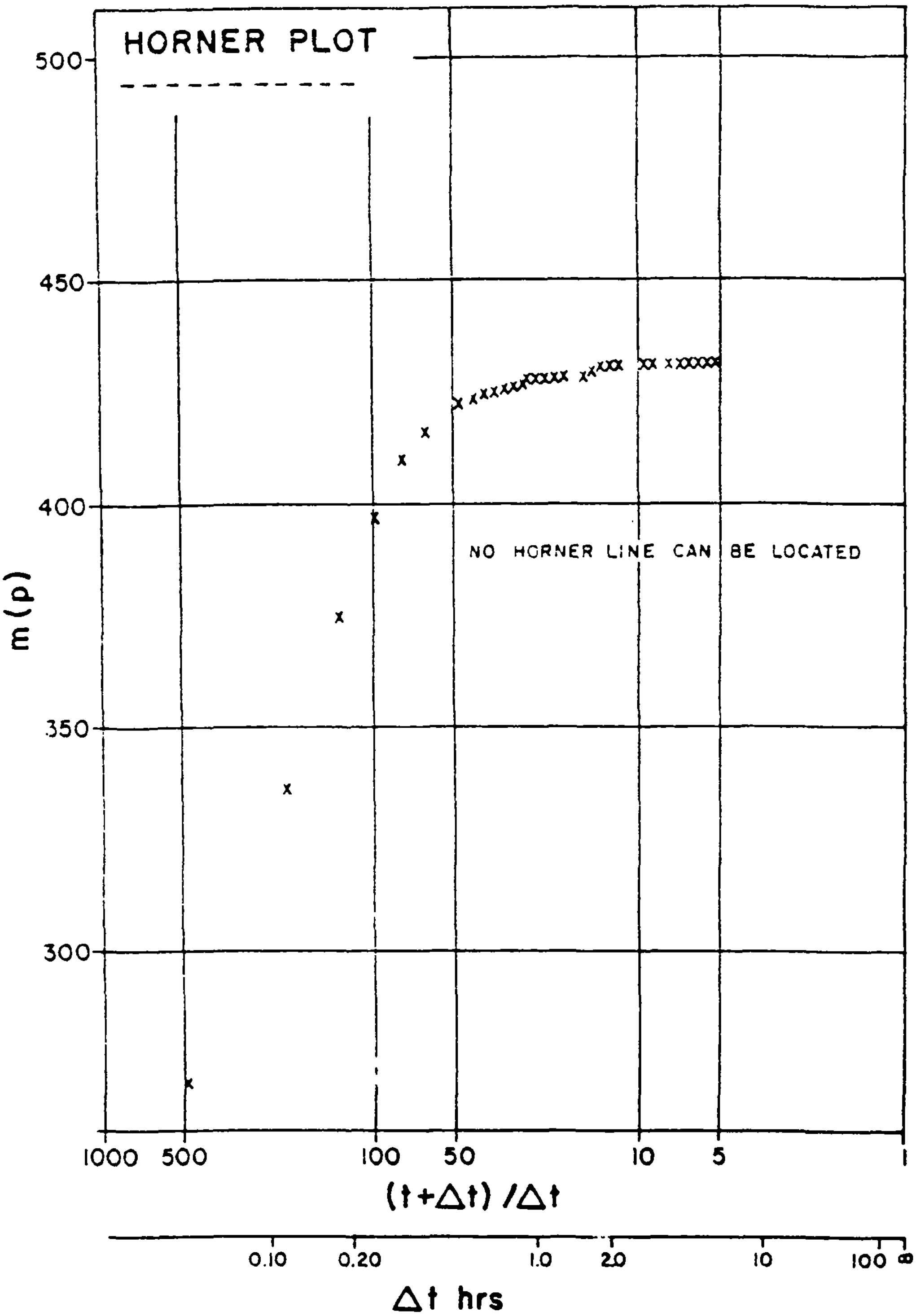
SEQUENTIAL RATE TEST NO 1 19.6.80

Reservoir pressure : $\bar{p}$ = 2279 psia, m $(\bar{p})$ = 431.2×10^{6} psia^2/cp at 1484 m BDF

Gas Rate MMSCF/D	Pwf psia	m (pwf) 10^6 psia^2/cp	$[m(\bar{p})-m(pwf)]/q$ 10^6(psia^2/cp)/(MMScf/D)
1.28	2045	357.6	0.5750
2.40	1785	281.0	0.6258
3.36	1456 (init.)	193.5	0.7074
3.36	1540 (final)	214.8	0.6440
5.20	1203 (init.)	135.3	0.5690
5.20	1265 (final)	148.9	0.5429
5.80	1360 (init.)	170.5	0.4495
5.80	1478 (final)	199.0	0.4003

The tabulation indicates that the well's inflow performance is improving during the test since the values in the extreme right column are decreasing with increasing rates. (With the presence of turbulence the values should increase with increasing rate). Thus the data cannot be used for estimating the effect of turbulence.

Table I/9.8



XXX ACTUAL BUILD UP SEMI-LOG STRAIGHT LINE

WELL 31/2-3 MICACEOUS SAND GAS TEST 1520-35M BDF - 1ST BUILDUP 19.6.80

m(p) IS PSEUDO PRESSURE/10^6 UNITS IN PSI^2/CP

a-s Norske Shell

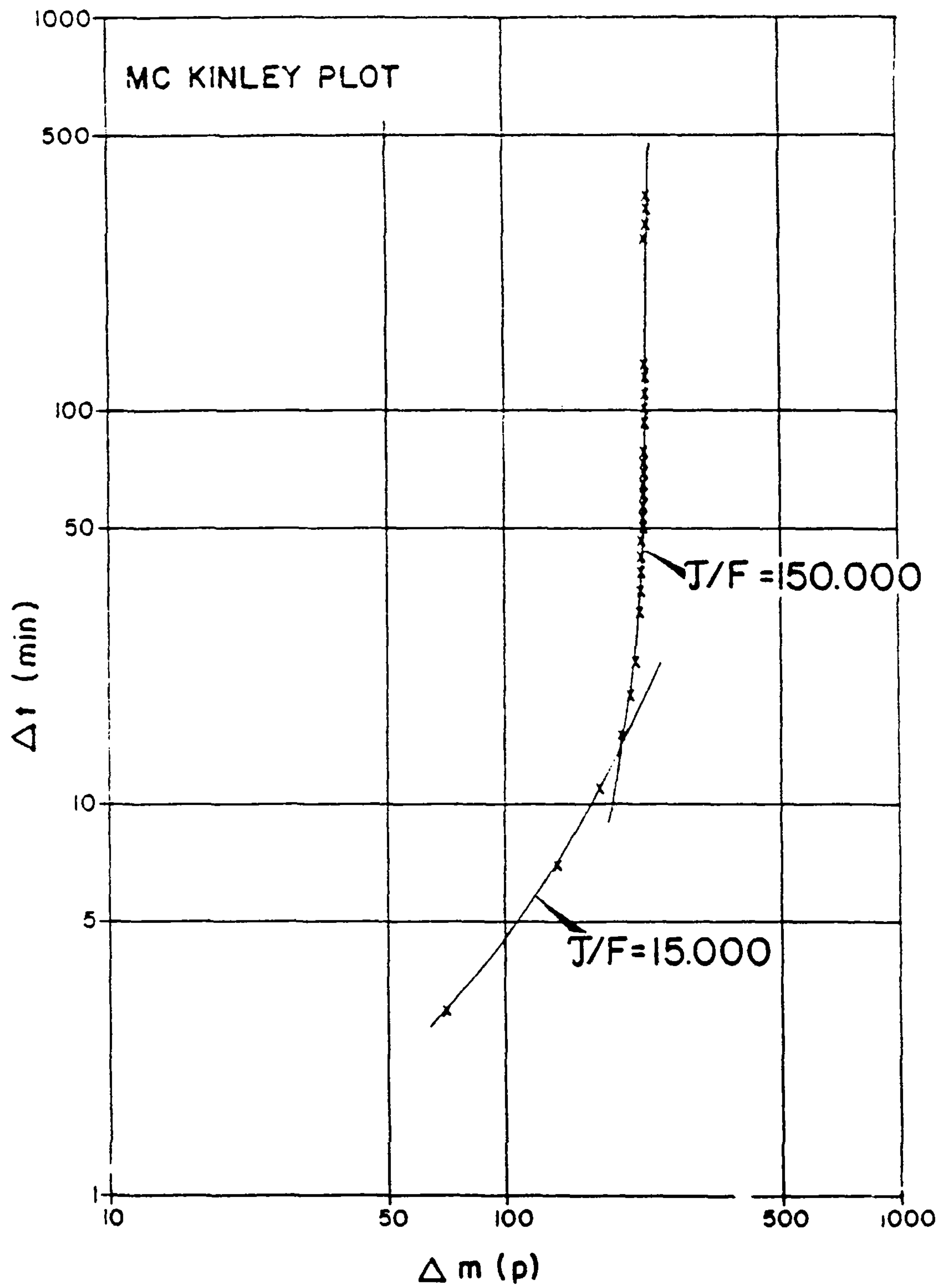
31/2-3

EXPLORATION WELL RESUMÉ

MICACEOUS SAND GAS TEST

HORNER PLOT FIRST BUILDUP

EPPP/22 FIG I/912



WELL 31/2-3 MICACEOUS SAND GAS TEST 1520-35 M BDF - 1ST BUILDUP 19.6.80
m(p) IS PSEUDO PRESSURE/10^6 UNITS IN PSI^2/CP

a.s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3
EXPLORATION WELL RESUMÉ
MICACEOUS SAND GAS TEST
MC KINLEY PLOT FIRST BUILDUP

EPPP/22 FIG I/9.13

[illegible]

[illegible]

[illegible]

Well bore radius	r_w	= [illegible] ft
Thickness (perforated length)	h	= 39 ft
Porosity	ϕ	= [illegible]
Reservoir pressure	p	= 2279 psia at 1424 m SDF
[illegible] before shut in	p_{wf}	= 1478 psia at 1424 m SDF
Gas rate before shut in	q_g	= 6000 MSCF/D
Cumulative production	G_p	= [illegible] MMSCF
Reservoir Temperature	T	= 144° F
Gas viscosity at p	μ_g	= 0.014 cp
Compressibility at p	c_t	= 550 x 10^{-6}/psi

HORNER PLOT

The plot shows that no reliable straight line portion can be found and hence no analysis is possible.

MCKINLEY TYPE CURVES

Early time fit for T/F = 15,000

Late time fit for T/F = 150,000

Match point on early time curve $\Delta m(p) = 100 \times 10^5$

for $(F' \Delta m(p) / q_g) = 1.3 \times 10^{-2}$ where F' is

wellbore storage in MMSCF/(psi^2/cp)

$$F' = ((F' \Delta m(p) / q_g) \times \frac{q_g}{m(p)} = 1.3 \times 10^{-2} \times \frac{6000}{100 \times 10^6} = 0.78 \times 10^{-6}$$

It can be shown that the wellbore storage, F, expressed in bbl/psi at reservoir conditions

$$F = 10 \left(\frac{T}{\mu}\right)_{wf} \times F' = 10 \frac{604}{0.014} \times 0.78 \times 10^{-6} = 0.34$$

Wellbore transmissibility	:	$T_w = (T/F) \times F = 15000 \times 0.34 = 5100$ mdft/cp
Permeability thickness	:	$kh = T_f \times \mu_{avg} = 51000 \times 0.015 = 765$ mdft
Permeability	:	$k = \frac{kh}{h} = \frac{765}{49} = 15.6$ md

SKIN CALCULATION

At the intersection of two type curves the following reading can be made for the late time curve:

$F' \Delta m(p) / q_g = 3.3 \times 10^{-3}$

which gives the pseudo pressure build-up corresponding to this curve

$$m(p)_{150,000} = (F' \Delta m(p) / q_g) \times \frac{q_g}{F'} = 3.8 \times 10^{-3} \times \frac{6000}{0.78 \times 10^{-6}} = 29.2 \times 10^{-6}$$

The real pseudo pressure buildup at the intersection

$\Delta m(p)_{15000} = 200 \times 10^6$

Pseudo pressure drop due to skin

$$\Delta m(p)_s = \Delta m(p)_{15000} - \Delta m(p)_{150000} = (200 - 29) \times 10^6 = 171 \times 10^5 \text{ psi}^2/\text{cp}$$

$$\text{Skin factor } S = \frac{\Delta m(p)s \times kh}{1422 q_g T} = \frac{171 \times 10^5 \times 755}{1422 \times 6000 \times 604} = 25.4$$

Flowing pseudo pressure excluding skin

$m(p)_{wf, \text{ no skin}} = m(p)_{wf} + m(p)_{skin} = (199.1 + 171) \times 10^6 = 370.1 \times 10^6$ psi^2/cp

which gives p_{wf}, no skin = 2086 psia

$\Delta p_s = p_{wf, \text{ no skin}} - p_{wf} = 2086 - 1478 = 608$ psi

$$\% \text{ of drawdown } \frac{\Delta p_s}{\Delta p} \times 100\% = \frac{608}{2279-1478} \times 100\% = 75\%$$

Table I/9.10

MICACEOUS SAND GAS TEST

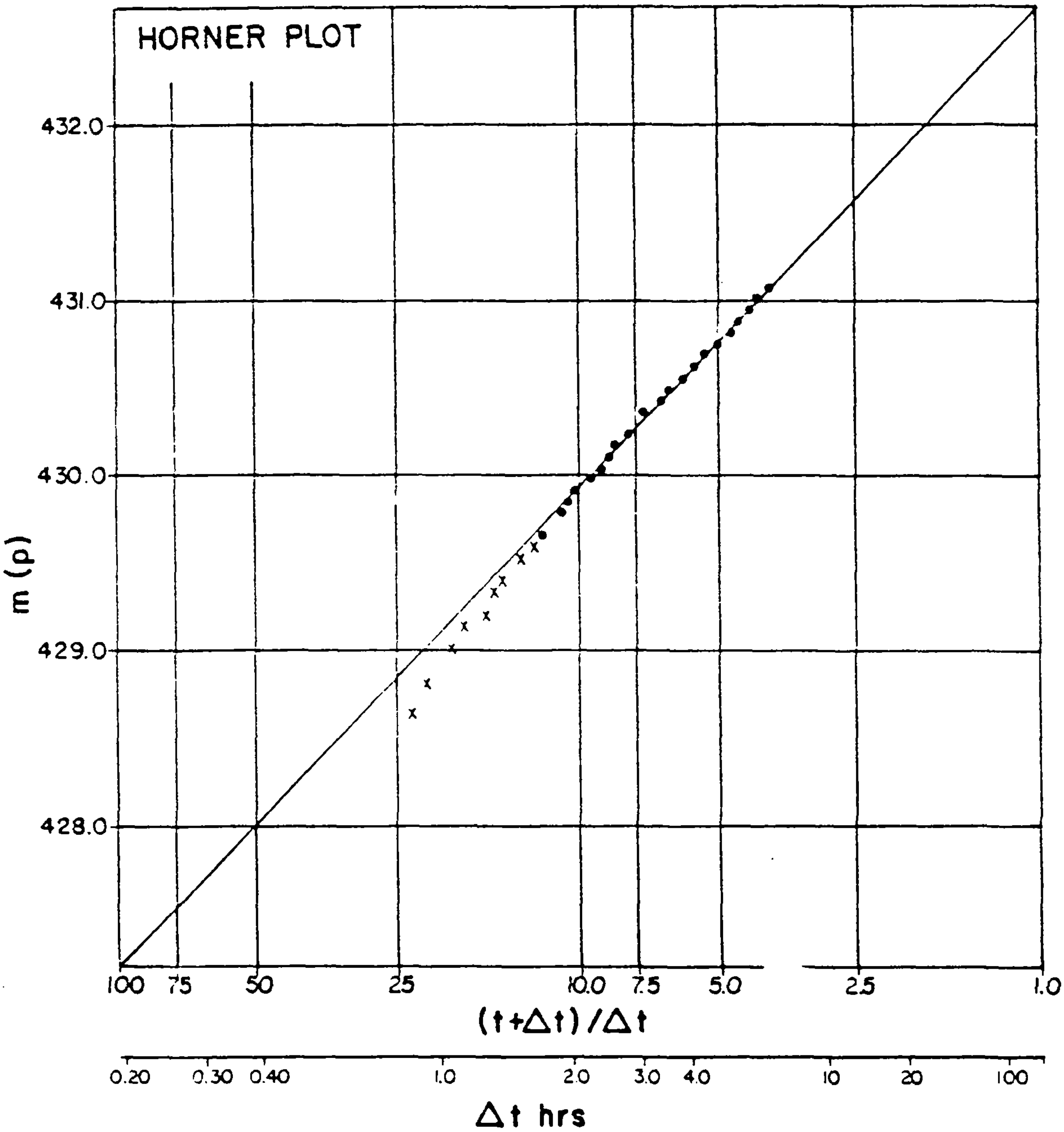
SEQUENTIAL RATE TEST NO 3 22.5.80

Reservoir pressure: $\bar{p}$ = 2279 psia, m ($\bar{p}$) = 431.2 psi^2/cp at 1484 BDF

Gas Rate MMScf/D	pwf psia	m(p) $10^6 (psi)^2/cp$	$[m(\bar{p})-m(p)wf] / q_T$ $10^6(psi^2/cp)/(MMSCF/D)$
16.011	1283.99	153.2	17.36
20.982	1201.09	135.0	14.12
23.011	1123.59	119.1	13.56
27.847	1118.19	118.0	11.25
30.132	1207.10	136.3	9.79
31.102	1222.32	139.6	9.38
32.587	1255.36	146.9	8.72

The inflow performance is still improving during this test since the values in the extreme right column are decreasing with increasing rates.

Table I/9.11



••• POINTS CHOSEN FOR SEMI-LOG STRAIGHT LINE
WELL 31/2-3 MICACEOUS SAND GAS TEST 1520-35M BDF - 3RD BUILDUP 23.6.80
m(p) IS PSEUDO PRESSURE/10^6 UNITS IN PSI^2/CP

a·s Norske Shell
EXPLORATION & PRODUCTION FORUS
31/2-3
EXPLORATION WELL RESUMÉ
MICACEOUS SAND GAS TEST
HORNER PLOT THIRD BUILDUP
EPPP/22
FIG. I/3.14

MICACEOUS SAND GAS TEST

PRESSURE BUILDUP ANALYSIS SECOND BUILDUP 22.6.80

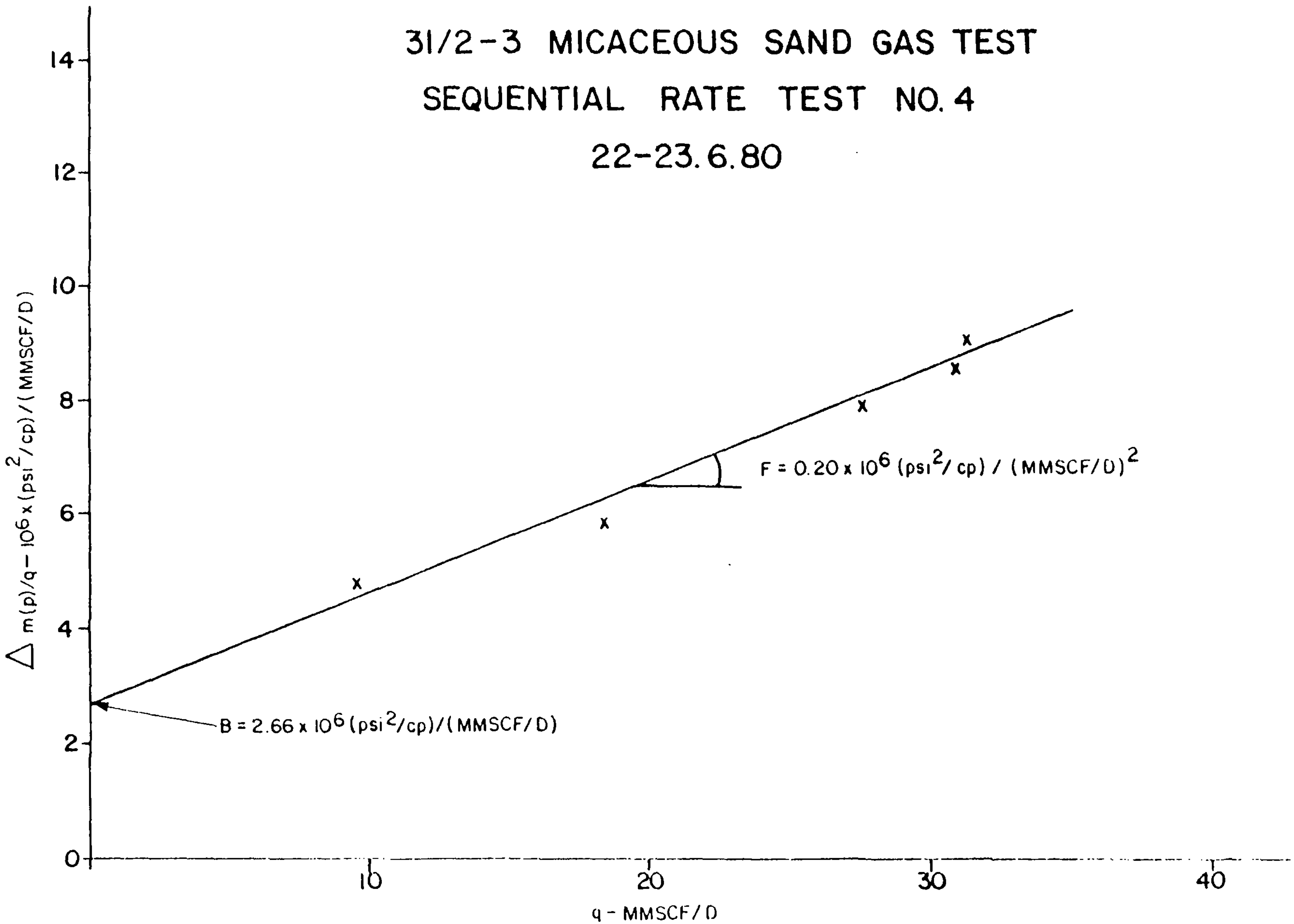
PARAMETERS

Well bore radius	r_w	= 0.51 ft
Thickness (perforated length)	h	= 49 ft
Porosity	ϕ	= 0.30
Reservoir pressure	$\bar{p}$	= 2279 psia at 1484 m BDF
BHFP before shut in	p_{wf}	= 1262 psia at 1484 m BDF
Gas production rate	q_g	= 32600 MSCF/D
Cumulative production	Gp	= 25.9 MMSCF
Reservoir temperature	t	= 144^0 F
Gas viscosity at $\bar{p}$	μ_g	= 0.017 cp
Compressibility at $\bar{p}$	c_t	= 450×10^{-6}/psi

HORNER ANALYSIS

Straight line slope	m	= 2.63×10^6 (psi^2/cp)/cycle
Permeability thickness	kh	= 12177 mdft
Permeability (h= perf. length)	k	= 248.5 md
Extrapolated pressure	p*	= 2283 psia
Pressure after 1 hr shut in	P_{1hr}	= 2273 psia
Skin factor (including turbulence)	S'	= 116
Pressure drop due to skin	Δps	= 965 psi
Skin - % of drawdown	95%	

Table I/9.12



a·s Norske Shell

31/2-3

EXPLORATION WELL RESUME
MICACEOUS SAND GAS TEST
SEQUENTIAL RATE TEST NO.4

FIG.
I/915

MICACEOUS SAND GAS TEST

SEQUENTIAL RATE TEST NO 4 23.6.80

Reservoir pressure : $\bar{p}$ = 2279 psia, $m(\bar{p})$ = 431.2 psi^2/cp at 1484 m BDF

Gas Rate MMSCF/D	pwf psia	m(p) $10^6 psia^2/cp$	$m(\bar{p})-m(p)wf$ /q $10^6 (psi^2/cp)/MMSCF/D)$
9.529	2135.15	385.5	4.79
18.303	1931.29	323.5	5.88
27.501	1531.19	212.6	7.95
30.750	1336.35	165.0	8.65
31.215	1250.04	145.7	9.14

Darcy coefficient B = $2.66 \times 10^3 (psi^2/cp)/(MSCF/D)$
Non-Darcy coefficeint F = 0.20 $(psi^2/cp)/(MSCF/D)^2$

Pseudo pressure drop due to turbulence at 32.6 MMScf/D
(rate prior to second buildup):

$\Delta m(p)nD = Fxq^2 = 0.20 \times 32600^2 = 213 \times 10^6 psi^2/cp$

which is 78% of drawdown when converted into pressure terms

The non-Darcy flow constant is

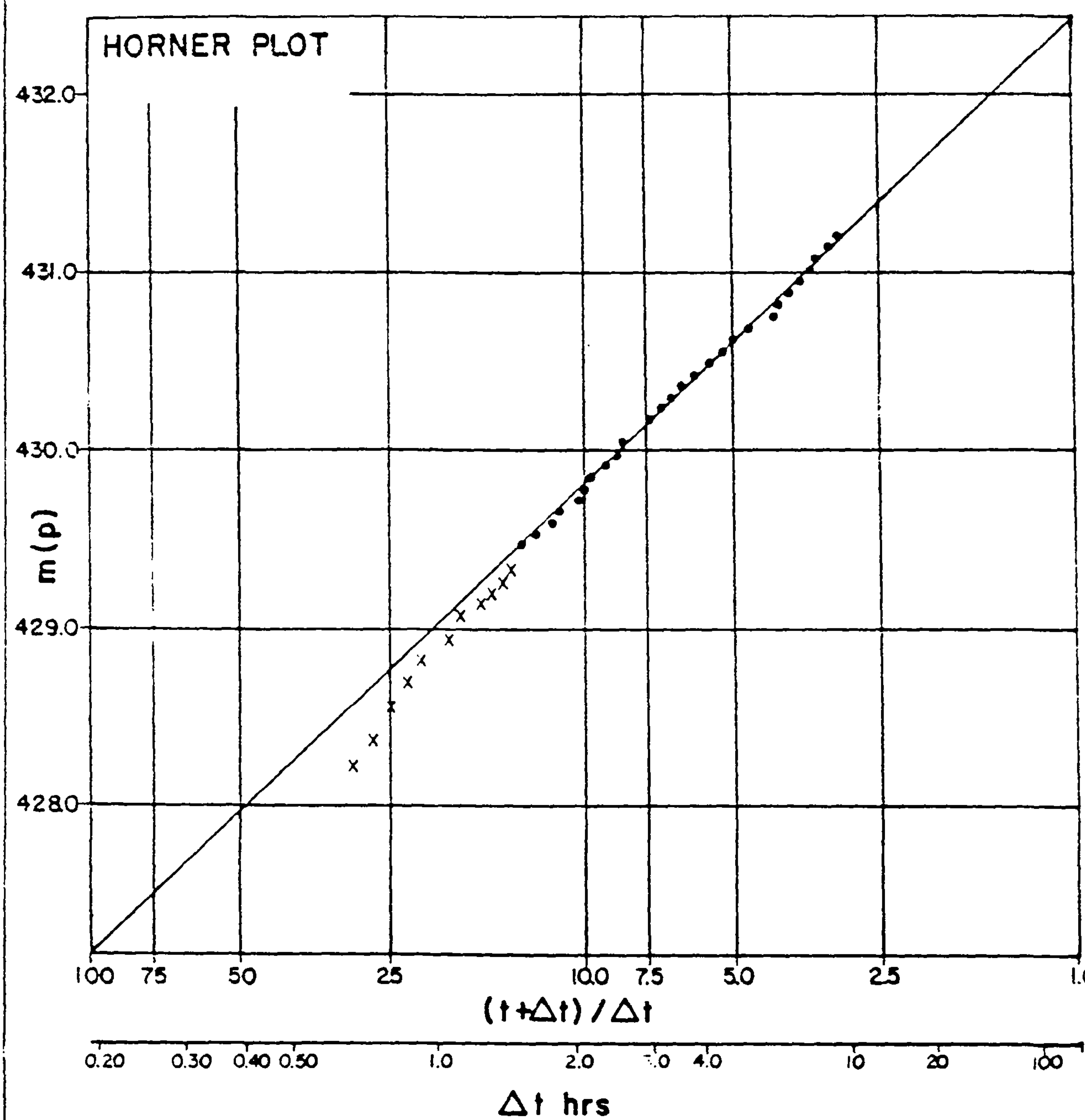
$$D = \frac{Fxkh}{1422T} = \frac{0.20 \times 12177}{1422 \times 604} = 2.84 \times 10^{-3}/(MSCF/D)$$

The Darcy skin factor is then

$S = S' - Dq = 116 - (2.84 \times 10^{-3} \times 32600) = 23.5$

which accounts for 17% of drawdown when converted into pressure terms.

After removing tubulence and Darcy skin effects only 5% of drawdown is left for Darcy flow drawdown on the formation.



••• POINTS CHOSEN FOR SEMI-LOG STRAIGHT LINE
WELL 31/2-3 MICACEOUS SAND GAS TEST 1520–35 M BDF – 2ND BUILDUP 22.6.80
m(p) IS PSEDO PRESSURE/10^6 UNITS IN PSI^2/CP

a-s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3
EXPLORATION WELL RESUMÉ
MICACEOUS SAND GAS TEST
HORNER PLOT SECOND BUILDUP

EPPP/22

MICACEOUS SAND GAS TEST

PRESSURE BUILDUP ANALYSIS THIRD BUILDUP 23.6.80

PARAMETERS

Well bore radius	r_w	= 0.51 ft
Thickness (perforated length)	h	= 49 ft
Porosity	Ø	= 0.30
Reservoir pressure	p	= 2279 psia at 1484 m BDF
BHFP before shut in	p_{wf}	= 1262 psia at 1484 m BDF
Gas production rate	q_g	= 31700 MSCF/D
Cumulative production	Gp	= 25.3 MMSCF
Reservoir temperature	t	= 144^0 F
Gas viscosity at p	μ_g	= 0.017 cp
Compressibility at p	C_t	= 450×10^{-6}/psi

HORNER ANALYSIS

Straight line slope	m	= 2.74×10^6 (psi^2/cp)/cycle
Permeability thickness	kh	= 11498 mdft
Permeability (h= perf. length)	k	= 234.7 md
Extrapolat ed pressure	p*	= 2284 psia
Pressure after 1 hr shut in	p_{1hr}	= 2273 psia
Skin factor (including turbulence)	S'	= 112
Pressure drop due to skin	Δps	= 972 psi
Skin - % of drawdown	96%	

Table I/9.14

CLEAN SAND GAS TEST

THORNTON RESULTS

These results are provisional and were telexed from the rig during the test. The full Thornton report and analysis has not been received yet.

TIME OF SAMPLING		STAGE 1			STAGE 2		
		Pressure psig	Temp °C	CGR BBl/MMSCF	Pressure psi	Temp °C	CGR BBl/MMSCF
7.7.80	2230	1000	-10	5.48	500	-11.3	1.02
8.7.80	0015	1000	+3	6.00	500	-13.8	1.43
8.7.80	0945	1000	+5.5	6.75	500	-11.1	1.27

Complete sets of samples were taken during these tests, for a well stream composition analysis. Glycol was being injected during the testing at +/- 3 galls/hour between 0100-0200 hrs 8.7.80.

Table I/9.16

CLEAN SAND GAS TEST

KSLA RESULTS

The results below are provisional and were telexed from the rig during the test; the final KSLA report has not been received yet.

The samples were taken from the separator. The main sampling period, on 8.7.80, was during the sequential flow period, with a flowrate ± 20 mmscf/d.

DATE	TIME	H_2S ml/m3	Hg mg/m^3	Rn pico Curic/l	H_2O in sep. gas % v/v	H_2O (in wellstream % v/v
4.7.80	1520	0.04				
	1537	0.06				
5.7.80	1017	0.04				
6.7.80	1920	0.06				
	2015	0.08	0.01			
	2105	0.08	>0.01	1.1		
7.7.80	1040	0.1				
	1100	0.09	0.02			
	1130	-	0.01			
	1340	0.08	0.01			
	1430	0.09				
	1515				0.09	0.03
8.7.80	0000	0.06	0.02			0.02
	0115	0.04			0.072	
	0230	0.06	0.06	1.0		
	0330	0.07			0.078	
	0400		0.05			0.02

Table I/9.17

CLEAN SAND GAS TEST

SEQUENTIAL RATE TEST NO 1 7.7.80

Reservoir pressure: $\bar{p}$ = 2271 psia, m ($\bar{p}$) = 437.2 psi^2/cp at 1375 m BDF

Gas Rate MMSCF/D	pwf psia	m(p) $10^6 psi^2/cp$	$[m(\bar{p}) - m(p)wf]/q$ $10^6 (psi^2/cp)/(MMSCF/D)$
9.63	2241	427.9	0.9657
20.70	2124	392.4	2.164
30.62	1976	348.6	2.894
39.50	1734	280.3	3.972

Darcy coefficient $B = 41.6\ (psi^2/cp)/(MMSCF/D)$

Non-Darcy coefficient $F = 0.0979\ (psi^2/cp)/(MMSCF/D)^2$

The inflow performance relationship resulting from these two coefficients is shown in Fig. 35 which demonstrates that the IPR is totally dominated by turbulence.

Since a value for kh cannot be obtained due to the fast buildup, an estimate of a minimum value can be obtained from the value of B.

For a circular drainage area

$$B = \frac{1422T}{kh}\left[\ln(0.47\ re/rw) + S\right]$$

which gives

$$kh = \frac{1422T}{B}\left[\ln(0.47\ re/rw) + S\right]$$

Assuming ln (0.47 re/rw) = 7 and the Darcy skin S = 0 a minimum kh value is obtained

$$kh_{min} = \frac{1442T}{B} \times 7 = \frac{1422 \times 604}{41.6} \times 7 = 144500 \text{ mdft}$$

and with h = 82ft (perf. interval)

$$k_{min} = \frac{(kh)min}{h} = \frac{144500}{82} = 1700 \text{ md}$$

However, with the very high turbulence, it is reasonable also to assume a high Darcy skin factor and thus much higher values for kh and k.

The non-Darcy flow constant for this kh is

$$D = \frac{Fkh}{1422T} = \frac{0.0979 \times 144500}{1422 \times 601} = 16.6 \times 10^{-3} / \text{(MSCF/D)}$$

The total skin factor including turbulence at 38100 MSCF/D (rate prior to fourth buildup) is then

$$S' = S + Dq = 0 + 16.6 \times 10^{-3} \times 38100 = 632$$

which is 99% of drawdown when converted into pressure terms.

Table I/9.18

PARAMETERS

Well bore radius	r_w	= 0.51 ft
Thickness (perforated length)	h	= 82 ft
Porosity	ϕ	= 0.30
Reservoir Pressure	p	= 2265 psia at 1404 m BDF
BHFP before shut in	pwf	= 1735 psia at 1404 m BDF
Gas production rate	qg	= 38100 MSCF/D
Cumulative production	Gp	= 2.5 MMSCF
Reservoir temperature	t	= 141^0 F
Gas viscosity at p	μg	= 0.017 cp
Compressibility	Cg	= 450 x 10^{-6}/psi

MCKINLEY TYPE CURVES

Early time for for $T/F = 2.5 \times 10^4$
There is no type curve with high enough T/F to fit the late time data. The curve with the highest $T/F = 1 \times 10^6$ is shown in Fig. 37. However, based on the late time data and the general change of the type curves with higher values of T/F, it is reasonable to assume that the correct T/F could be as high as 1×10^8.

Early time match point : $\Delta m(p) = 50 \times 10^6$ for
$(F'\Delta m(p)/q\,g) = 1.3 \times 10^{-3}$ where F' is wellbore storage in MSCF/(psi^2/cp)

$$F' = (F'\Delta m(p)/q\,g) \times \frac{q\,g}{m(p)} = 1.3 \times 10^{-3} \times \frac{38100}{50 \times 10^6} = 0.99 \times 10^{-6}$$

Wellbore storage in BBL_{res}/psi

$$F = 10\left(\frac{T}{\mu}\right)_{wf} \times F' = 10 \times \frac{601}{0.015} \times 0.99 \times 10^{-6} = 0.397$$

Wellbore transmissibility $T_w = (T/F)_w \times F = 2.5 \times 10^4 \times 0.397 = 9917$ mdft/cp

Assuming $(T/F) = 1 \times 10^8$ for the late time data gives the formation transmissibility as

$$T_f = T_w \times \frac{(T/F)f}{(T/F)w} = 9917 \times \frac{1 \times 10^8}{2.5 \times 10^4} = 39.7 \times 10^5 \text{mdft/cp}$$

which gives for the formation

$$(kh)_f = T_f \times \mu_{avg} = 39.7 \times 10^5 \times 0.016 = 635 \times 10^3 \text{ mdft}$$

$$kf = \frac{(kh)f}{h} = \frac{635 \times 10^3}{82} = 7.74 \times 10^3 \text{ md} = 7.74 \text{ D}$$

Using the Darcy coefficient from the sequential rate flow test, B, an estimate of Darcy skin factor for this high kh can be made.

$$B = \frac{1422\,T}{kh}\left\{\ln\ (0.47\ re/rw) + S\right\}$$ and assuming

ln (0.47 re/rw) = 7 the Darcy skin factor is

$$S = \frac{B \times kh}{1422\,T} - 7 = \frac{41.6 \times 635 \times 10^3}{1422 \times 601} - 7 = 24$$

The non-Darcy flow constant for this kh is

$$D = \frac{Fkh}{1422T} = \frac{0.0979 \times 635000}{1422 \times 601} = 73.3 \times 10^{-3}/\ (\text{MSCF/D})$$

The total skin including turbulence at 38100 MScf/D is then:
$S' = S + Dq = 24 + 73.3 \times 10^{-3} \times 38100 = 2800$
which is close to 100% of drawdown when converted into pressure terms.

SAND PREDICTION AND DETECTION RESULTS 31/2-3

Introduction

Shell Research have conducted a theoretical study on sand failure prediction and confirmed the results with field data obtained from worldwide sources.
The result has been a correlation of failure stress with rock hardness. The latter, expressed as a Brinell Hardness Number (BHN), is readily measured in the laboratory; if the BHN is known, and in situ rock stresses can be estimated, the chances of sand production may be evaluated. The effect of drawdown is incorporated by regarding it as an additional stress, so that a prediction model is obtained which yields likelihood of sand failure as a function of stress level (including drawdown) and BHN.

Core samples of well 31/2-3 were sealed and sent to the Shell Research Laboratory in Rijswijk (KSEPL) for BHN determination.

The results are tabulated below:

INTERVAL	CORE DEPTH (M, BDF)	BHN (KG/MM^2)
"Main gas zone"	1431.0-1431.15	0.3
	1437.8-1437.93	*
	1459.55-1459.75	0.8
	1486.97-1487.14	0.3
"Mic gas zone"	1514.21-1514.50	1.1
	1515.72-1516.04	0.8
	1518.94-1519.24	0.4
	1525.09-1525.33	0.8
	1533.65-1533.66	0.7
"Oil zone"	1568.95-1569.10	0.5
	1574.65-1574.90	0.9
	1583.70-1584.02	1.0

* Rock too coarse-grained and loosely consolidated to measure.

These results without exception indicate very weak rock, and according to the criteria determined by KSEPL, perforation collapse and sand production could be expected even at low drawdowns. As a test of these laboratory findings, it was decided that an evaluation of sand production in the more consolidated oil zone and micaceous gas zone would be a useful secondary objective of the production tests; therefore, no sand control measures were taken for these intervals. On the main gas zone, however, the primary test objective of high rate gas production dictated that the surface equipment should be protected and a gravelpack was programmed.

Sand detection equipment

Two pieces of equipment were installed for the measurement of sand production:

a) Flopetrol 'SANDEC' probe
b) Baker sand trap.

...../2

These two items were situated at surface immediately downstream of the test tree.
The SANDEC equipment consists of a probe inserted into the flow path; it monitors impingements, and the signal is registered on a recorder either in a 'counts per second' mode or in a cumulative mode.

The Baker sand trap only became available on 22nd June 1980 and was used as from the last flow period of the micaceous gas zone test. It consists of a series of angle iron sections through which the gas flow is directed; in principle, solid particles such as sand grains will impinge on the angle iron and will drop to the bottom. Here, a sump is located which may be emptied as required. The sandtrap is provided with a bypass.

The sandtrap is intended to safeguard downstream equipment and as it should catch all sand passing the SANDEC, it may also be used to calibrate tool response.

Results

i) Oil zone test (1577.5 - 1582.5 m)

In this test, the SANDEC equipment was not in use. No sand was detected in samples taken at surface during the test. After concluding the test and killing the well, a bailer was run which retrieved a mixture of brine and fine sand from 1593 m (Note: bridgeplug at 1594 m).

ii) Micaceous gas test (1520 - 1535 m)

a) Clean-up phase: 15th June 0845 - 16th June 1700 hrs. First sand detected was a slight burst at 0730 hrs on the 16th. Apart from that, no sand was registered. It should be noted that at the low rate (5 MMSCF/D at 1200 psi), the velocity in the test spool is 5-6 m/s which is the minimum for the detection of small sand particles.

b) Sequential rate test I: 18th June 0400 - 19th June 0730 hrs. Minimal traces of sand detected.

c) Sequential rate test II: 19th June 1330 - 20th June 0200 hrs. No sand detected. Gas velocity in spool of 4 m/s which is too low.

d) 'Maximum flow rate test': 20th June 0845 - 1730 hrs. At 1100 hrs the well was beaned up to 56/64" choke and a high sand production was indicated (up to 2000 impacts/sec); upon beaning back to 48/64" the sand production ceased. This phenomenon was repeated when the well was beaned up and back down again to 48/64". No more sand production was registered. The sand production detected in this test is associated with the well cleaning up.

e) Sequential rate test III: 21st June 0400 - 22nd June 0230 hrs. Cleaning up of the well occurred. Whenever the choke size was increased a burst of sand was produced which would cease after 5-30 minutes. After the last choke increase (at 1345 hrs) the sand production reduced to a very low background level although the well was then producing in the order of 30 MMSCF/D. The adjustable choke was found to be eroded at this stage and it was changed out. The total amount of sand collected was only half a cupful of fine sand (25-200 micron) flushed out of the separator at the end of this test.

...../3

f) Sequential rate test IV: 22nd June 1215 - 23rd June 1800 hrs. Initial period (28/64" choke, rate 9.5 MMSCF/D): no sand recorded, no sand in sandtrap.

Second period (chokes 40/64" - 72/62", rate 18-29 MMSCF/D): Very little sand production, except for 30 min strong indication of sand when well was beaned up to 72/64" then back to 64/64". The sandtrap caught 0.35 g sand in one hour during a steady flow period (18 MMSCF/D).

Final period (choke 30/64" - 128/64", rate 30.5 - 34 MMSCF/D): Fair amount of sand, which increased whenever the choke was opened further. 6 grams sand was recovered from the sandtrap which was in operation for the final 1h 35min (128/64" choke, 34 MMSCF/D).

iii) Main gas test (1435-1460 m)

Though the interval was gravelpacked, the sand detection equipment was used as above to evaluate the effectiveness of the pack. Initially, no sand was produced except for minor, short-lived peaks whenever the well was beaned up. However, after the well was beaned up from 48/64" to 56/64" (6/7/80 around 1930 hrs - rate increased from 24 to 28 MMSCF/D) a more or less steady sand signal was obtained of 20-50 impacts/second, with more prolonged peaks (c. 30 minutes) whenever the well was beaned up further. This pattern was consistent throughout the production test.

Conclusions and Discussions

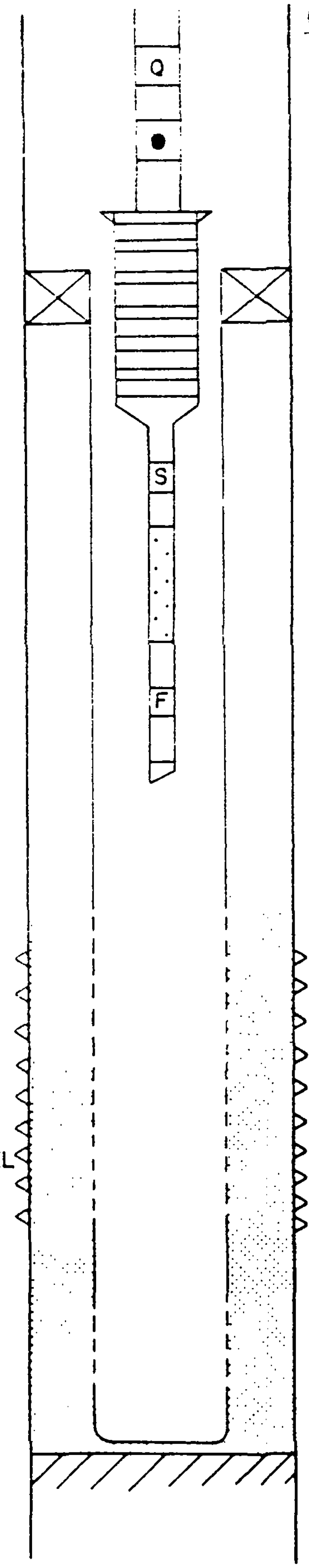
1. Hardly any sand was produced during the oil zone test.

2. The Micaceous gas zone produced a fair amount of sand during cleanup; after the well has cleaned up properly, sand production would drop to a very low level provided the choke setting was not altered, except at the highest rates where sand production was indicated by the SANDEC tool.

3. The main gas zone, in spite of being gravelpacked, produced some sand. Whether this was a transitory clean-up phenomenon or a failure of the gravelpack is difficult to say.

The use of the Baker sand trap gave operational problems. It takes up a lot of space and is cumbersome to operate. Moreover, the test results can be somewhat influenced by it since it knocks out liquid droplets as well as sand from the gas stream. The impression was gained that fine sand will pass through the sandtrap and collect in the separator. The correlation of sand quantities recovered from the sand trap with the SANDEC readings was not conclusive, and it was felt that more experience with this equipment is desirable. The SANDEC 'impacts per second' could therefore only be used as a qualitative measure of sand production.

31/2-3 CLEAN SAND GAS TEST ASSEMBLY



	DEPTHS m BDF (TOP OF ITEM)
Q NIPPLE	1376.1
XA - SSD	1381.3
G-22 LOCATOR SEAL ASSY	1385.3
BAKER SC-1 PACKER	1388.5
S-1 NIPPLE	1392.9
PERFORATED JOINT	1396.3
F NIPPLE	1399.3
PRESSURE BOMBS	
MULE SHOE	1408.4
TOP OF WWS	1433.5
TOP OF PERFORATIONS	1435.0
BOTTOM OF PERFORATIONS	1460.0
BOTTOM OF WWS	1460.7
TOP OF TELL TALE	1462.2
BOTTOM OF TELL TALE	1463.4
TOP OF CEMENT RETAINER	1464.0

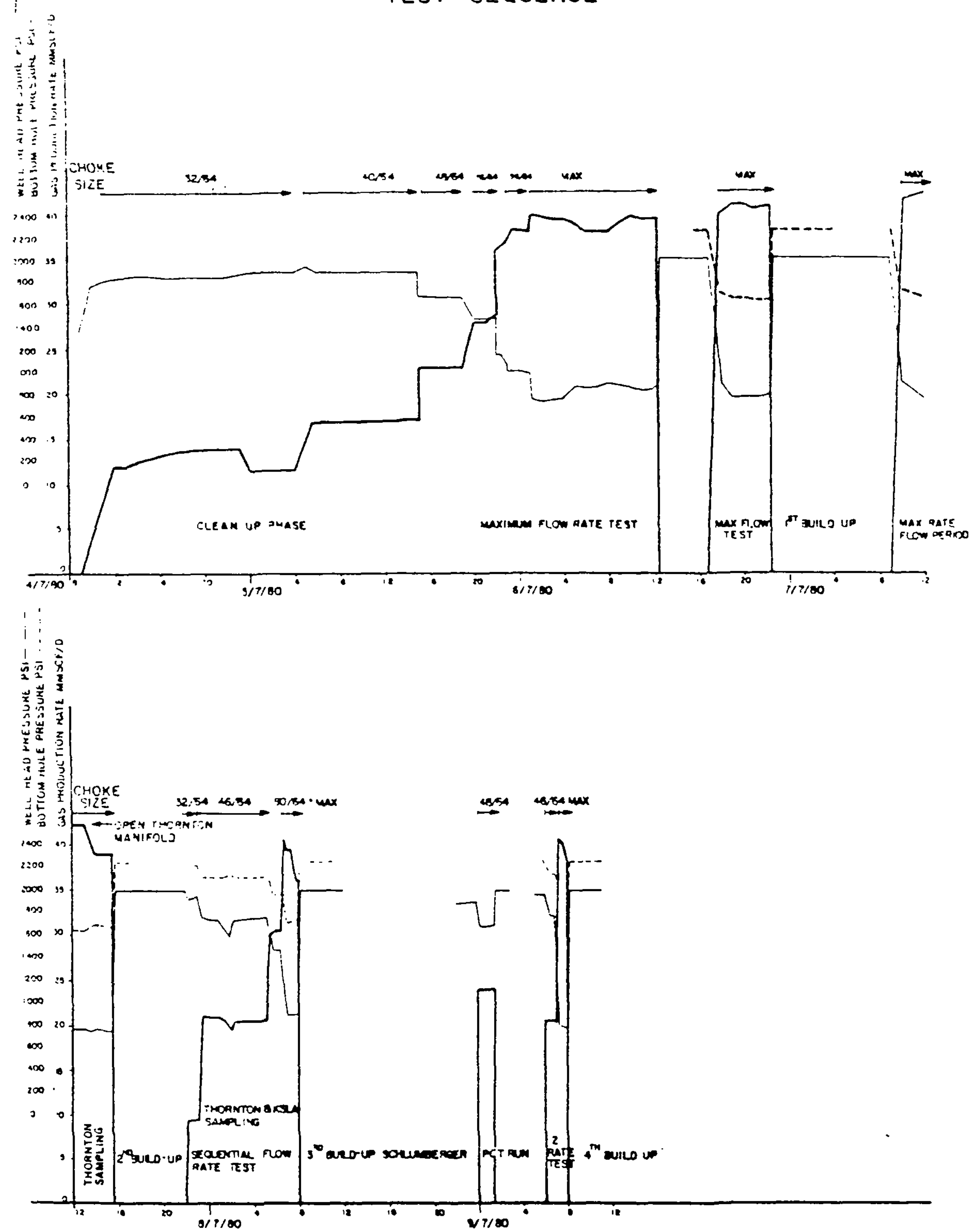
PERFORATIONS:
2 1/8" HYPERDOME SCALLOP
8 s.p.f. ZERO DEGREE PHASING

·012" GAUGE GAUGE SCREEN
20-40 MESH "LOW FINES" GRAVEL

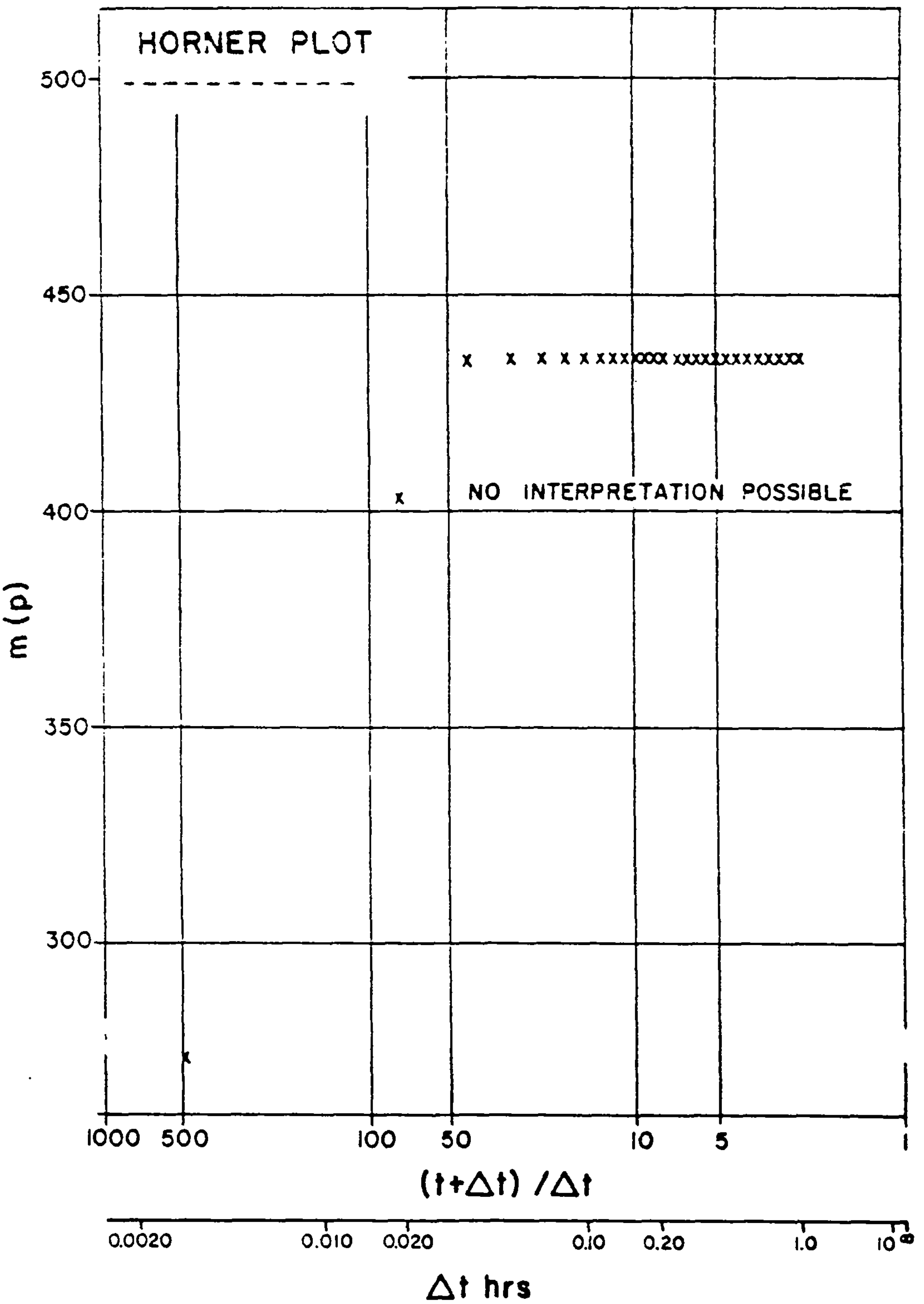
TUBING CONTENTS (+VOLUME BELOW PACKER) = ± 95 bbls.

a-s Norske Shell
EXPLORATION & PRODUCTION FORUS
31/2-3
EXPLORATION WELL RESUMÉ
CLEAN SAND GAS TEST
TEST ASSEMBLY
EPPO/3 FIG. I/9.17

WELL 31/2-3 CLEAN SAND GAS TEST
TEST SEQUENCE



a·s Norske Shell EXPLORATION & PRODUCTION FORUS		
31/2-3 EXPLORATION WELL RESUMÉ CLEAN SAND GAS TEST TEST SEQUENCE		
AUTHOR EPPO/3	FIG. I/9.18	DATE
REPORT NO		DRAW NO



XXX ACTUAL BUILD UP SEMI-LOG STRAIGHT LINE

WELL 31/2-3 CLEAN SAND GAS TEST 1435-60 M BDF - 1 ST BUILDUP 6.7.80

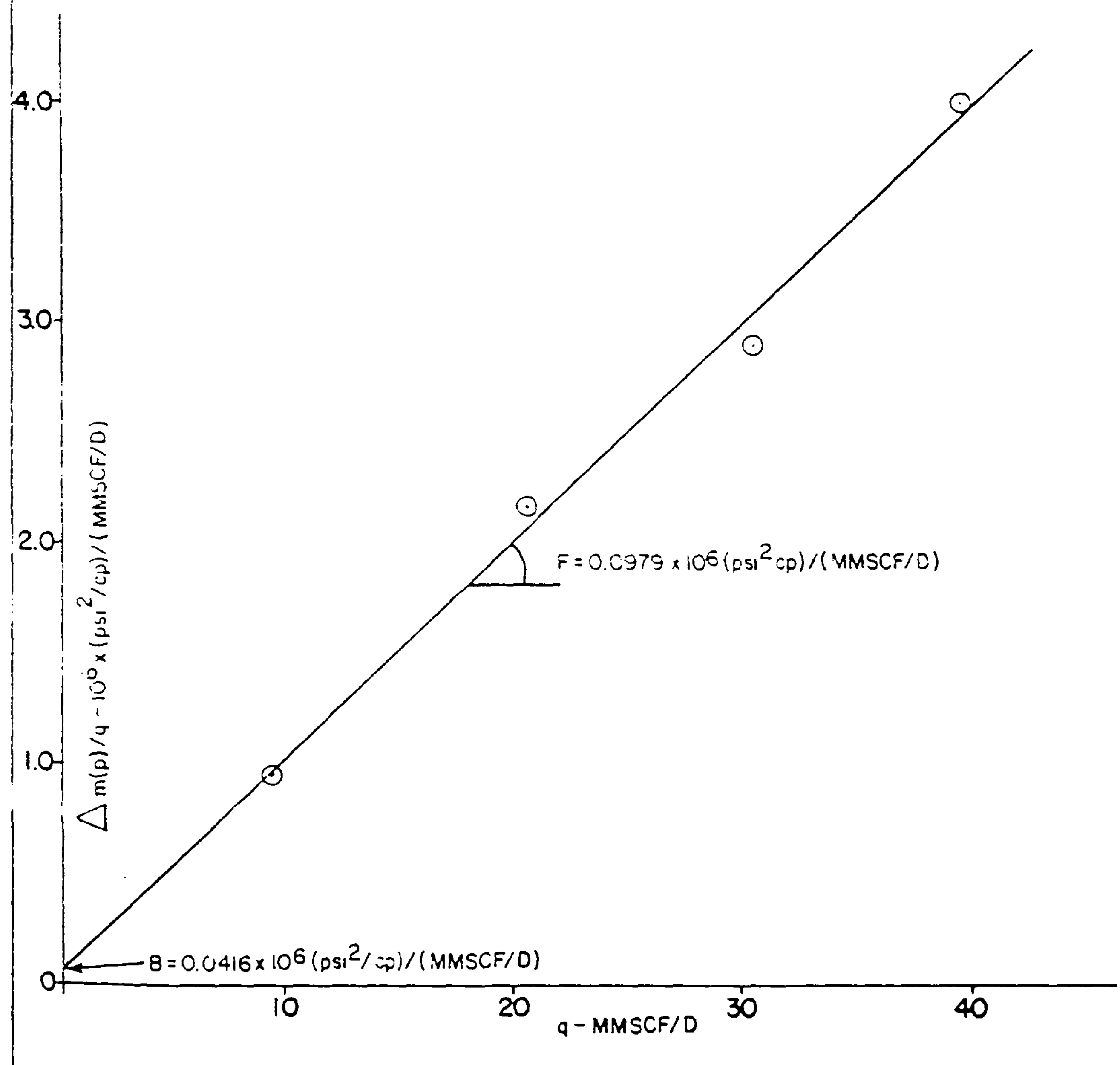
m(p) IS PSEUDO PRESSURE/10^6 UNITS IN PSI^2/CP

a·s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3
EXPLORATION WELL RESUMÉ
CLEAN SAND GAS TEST
HORNER PLOT FIRST BUILDUP

AUTHOR EPPP/22 FIG. DATE
REPORT NO. I/919 DRAW NO.

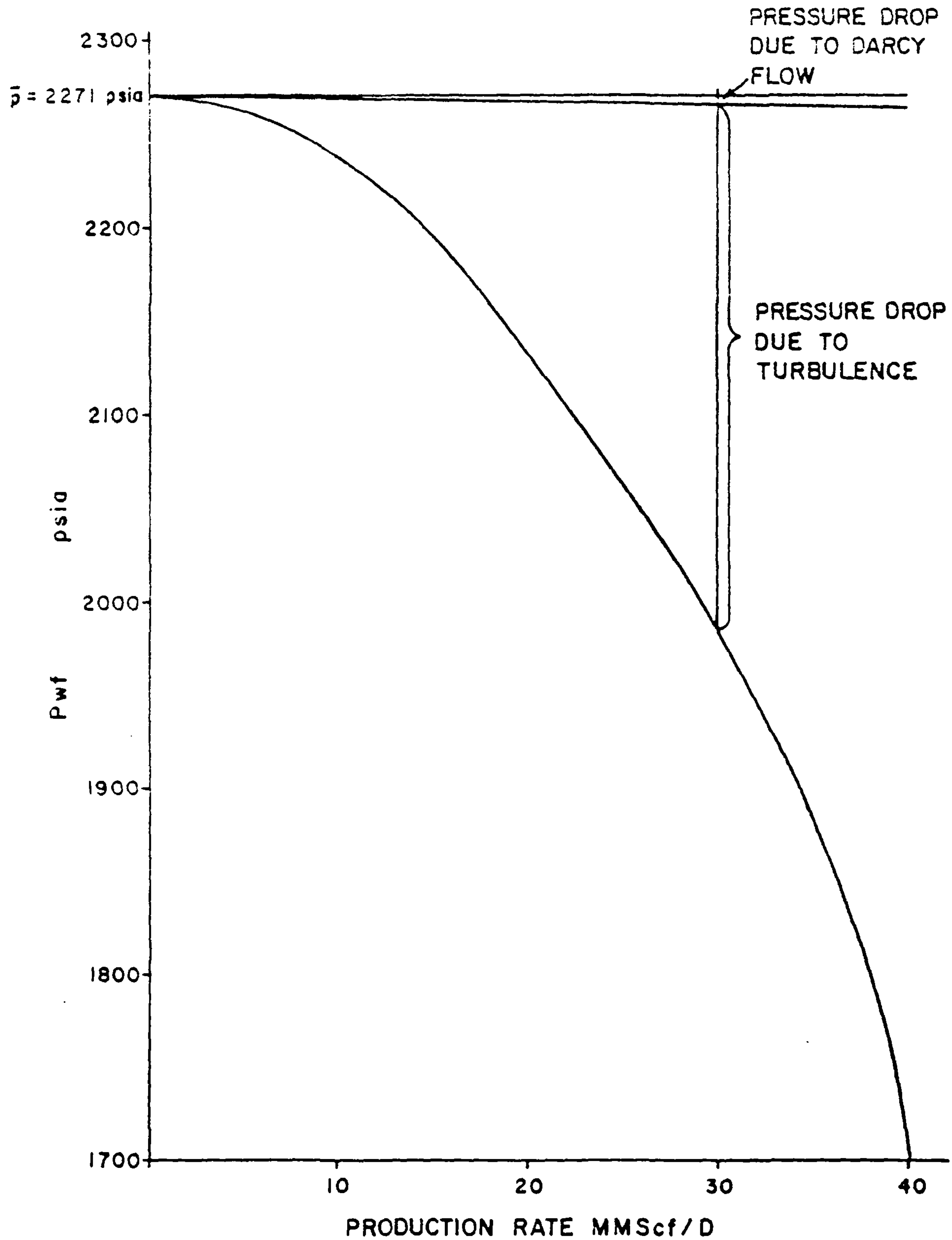
31/2-3 CLEAN SAND GAS TEST
FIRST SEQUENTIAL RATE TEST
8.7.80



a·s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3
EXPLORATION WELL RESUMÉ
CLEAN SAND GAS TEST
FIRST SEQUENTIAL RATE TEST
FIG
I/920

31/-3 CLEAN SAND GAS TEST
DRAWDOWN ANALYSIS

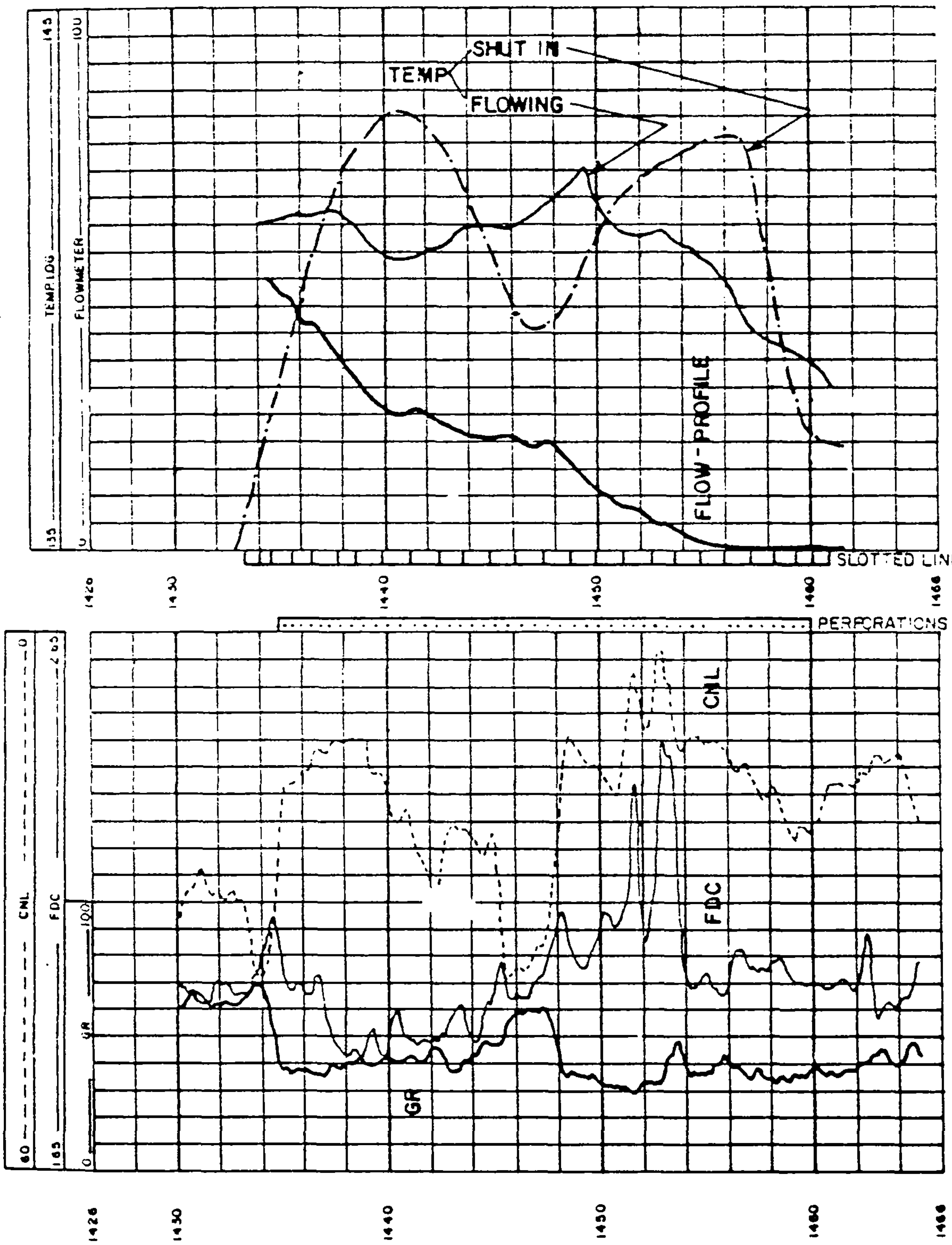


a-s Norske Shell
EXPLORATION & PRODUCTION FORUS

31/2-3
EXPLORATION WELL RESUMÉ
CLEAN SAND GAS TEST
DRAWDOWN ANALYSIS

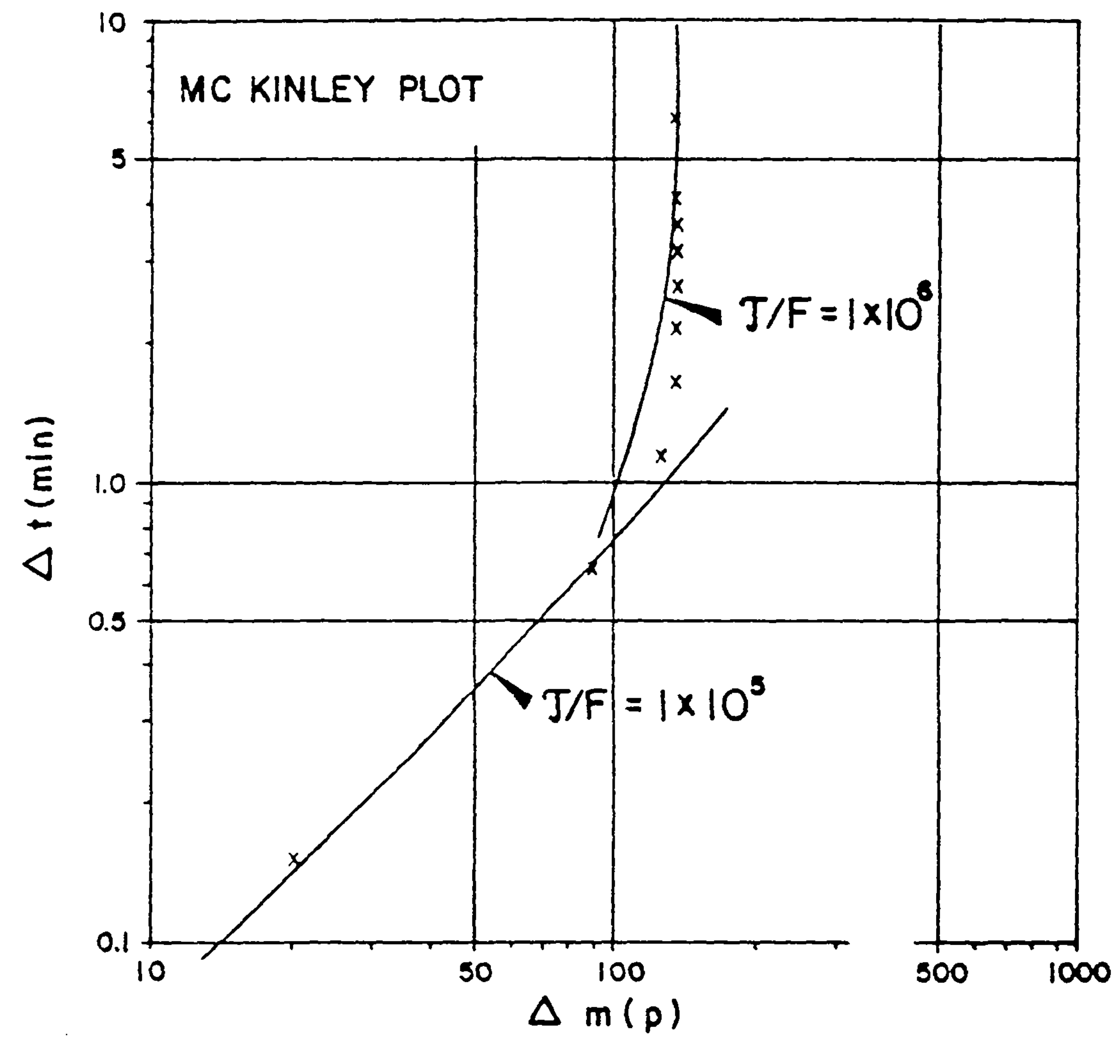
EPPO/3 FIG. I/921

PRODUCTION LOGGING SURVEY ON WELL 31/2-3



a-s Norske Shell
EXPLORATION & PRODUCTION FORUS
31/2-3
EXPLORATION WELL RESUMÉ
CLEAN SAND GAS TEST
PRODUCTION LOGGING SURVEY

AUTHOR EPPP/12	FIG.	DATE
REPORT NO	I/922	DRAW NO



WELL 31/2-3 CLEAN SAND GAS TEST 1435-60 M BDF - 4TH BUILD-UP 9.7.80
m(p) IS PSEUDO PRESSURE/10^6 UNITS IN PSI^2/CP

a-s Norske Shell EXPLORATION & PRODUCTION FORUS	
31/2-3 EXPLORATION WELL RESUMÉ CLEAN SAND GAS TEST MC KINLEY PLOT FOURTH BUILDUP	
AUTHOR EPPP/22	FIG. I/923